PV TECH POWER

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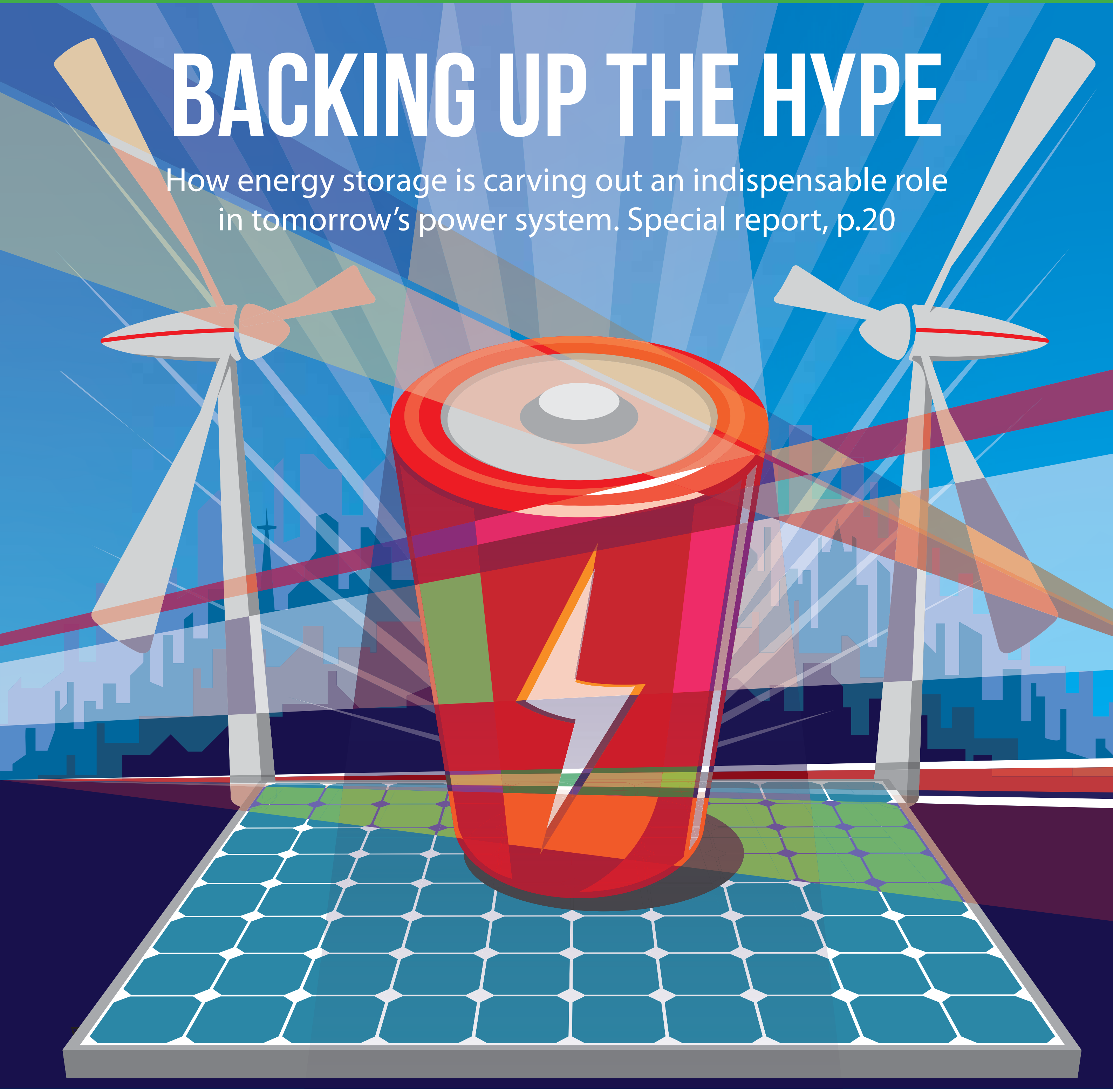
BACKING UP THE HYPE

How energy storage is carving out an indispensable role in tomorrow's power system. Special report, p.20



About LONGi Solar

LONGi Solar is a world leading manufacturer of high-efficiency monocrystalline solar cells and modules. Headquartered in Xi'an, China, the Company has branches in Japan, Europe, North America, India and Malaysia.

LONGi Solar is a wholly owned subsidiary of LONGi Group (SH601012) - the largest supplier of monocrystalline silicon solar wafers in the world with 12 GW of wafer capacity by year-end and plans to expand to 20 GW by 2019. With strong focus on R&D, LONGi is active in the entire monocrystalline silicon value chain, including solar power plants.

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Introduction

Welcome to the latest edition of *PV Tech Power*. This is a special issue for a number of reasons. The journal has now been running for five years with a growing roster of industry experts sharing in-depth know-how on everything from contract law to the pitfalls of east-west module layout.

It's also a special issue for us as it is the tightest marriage yet of *PV Tech's* decade-plus of solar industry coverage and the expert analysis and reporting of our sister site *Energy-Storage.News*.

Our 19-page special report in this issue explores both the accomplishments of the energy storage sector and the ongoing challenges. Fittingly, Andy Colthorpe, editor of *Energy-Storage.News*, sets the scene (p.20). He lays bare the rise in deployment, the cost reductions and the regulatory hurdles overcome and yet to clear as the industry establishes itself and beds in for a boom as part of the mainstream power sector.

A paper by Aachen University charts the advances of stationary battery storage systems and the emerging trends across a variety of applications (p.24).

Energy storage has been enabling the ongoing deployment of renewables in California as it pursues its 2045 decarbonisation goals. A paper in this issue from Strategen Consulting explores this and a host of other challenges in the Golden State that storage is tackling head on, from growing EV demand to displacing pricy and polluting gas peaker plants (p.32).

Looking ahead we investigate the growing trend for DC-coupled storage systems in the US in particular and at all scales (p.29).

VDE's Jan Geder meanwhile, looks at the very necessary technical work going on to ensure that the energy storage boom is both bankable and insurable (p.40). These are objectives that cannot be reached without the development of rigorous standards to guide both quality and safety.

Recycling is another area where the storage sector has more to do. The consultancy firm Li-Cycle explains why a battery powered future means creating recyclable products now, or risk jeopardising the tech's positive legacy (p.45)

Our regular Storage & Smart Power section also includes a feature from UK editor Liam Stoker taking a deep dive into the role of storage and other technologies limiting the damage done by a major blackout in the UK this summer (p.114).

This edition is not universally focussed on storage however. PV Evolution Labs' Michael Mills-Price and Jenya Meydbray discuss their inverter scorecard report. As the main driver of corrective maintenance they argue the case for comprehensive quality benchmarks in inverters (p.94).

José Rojo looks at two of Latin America's most vibrant markets, Mexico and Brazil. He discovers that many of the negative observations made from afar carry no weight when examined close up, with opportunities outstripping the remaining challenges (p.51).

We also have an update on Taiwan's solar market as the focus shifts from pure manufacturing to deployment as well (p.59), a closer look at the impact of the bifacial trade tariff exemption in the States (p.48) and much more.

Thanks as always for reading and do sign-up for the *PV Tech* and *Energy-Storage.News* newsletters for all the latest in these two growing, vibrant and symbiotic sectors.

John Parnell
Head of content

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HUAWEI

FusionSolar Residential & Commercial
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EUROPE

Portugal

Portugal claims spot in solar history with record-low auction prices

Portugal's latest solar auction concluded this summer with record-smashing low prices, *PV Tech* learned from a top official. Speaking before the government formally published the results in August, Energy state secretary João Galamba confirmed the lowest bid at the PV tender, made by Akuo's 150MW project, came in at €14.76/MWh (around US$16). Galamba described the figure – far below the auction's ceiling prices of €45/MWh (US$50/MWh) – as a "new world record." The tender also awarded 149MW worth of contracts to Iberdrola under a second modality, which saw the firm pay in return for grid space for its first ever Portuguese projects.

Credit: Solar Media

Most PV auction winners were foreign firms, Galamba told PV Tech.

Europe-wide prospects

Solar-plus-storage grid parity sweeps through top EU markets

The costs of residential solar-plus-storage have already dropped or will take little to drop to nation-wide grid averages in Europe, according to Wood Mackenzie. Storage systems installed across Europe's homes will boom by a factor of five to hit a cumulative 6.6GWh by 2024, the firm predicted in analysis released in August. According to Wood Mackenzie's Rory McCarthy, the momentum will be driven by the "economic tipping point" residential storage is experiencing, particularly around solar-collocated systems. These hybrids are, the senior research analyst explained, fast leaving behind the "challenges" of past years and approaching grid parity status across major European countries, particularly Italy and Germany.

Top utility-scale investor eyes subsidy-free surge in Southern Europe

Europe's subsidy-free solar scene is "developing rapidly", one of the continent's top utility-scale investors said over the summer. Foresight Solar Fund, which owns more than 700MW of utility-scale solar in the UK, used its interim result disclosure on 22 August to explain it is keeping an eye on subsidy-free developments in Europe after witnessing a surge in subsidy-free economics of late. It paid particular mention to the Spanish and Portuguese markets, where it said especially attractive PPA structures are sparking a wave of new activity.

Solar touted as 185,000-job lifeline for Europe's coal heartlands

Tumbling costs could see PV help Europe's coal regions navigate a tough transition away from the fossil fuel, SolarPower Europe said this summer. Walburga Hemetsberger, CEO of the association, argued solar can help ensure "no one is left behind" in the EU's clean energy shift after an official study described the industry as a "lifeline" for the bloc's coal-reliant economies. The analysis, carried out by EU scientists, found installing 580GW of solar across Germany, Poland and other coal hotspots within 15 years would bring 135,000 construction jobs every year, with a further 50,000 added through O&M work. The boom would offset much – but not all – of the job losses expected from fully phasing out today's EU coal portfolio, the study found.

Germany

German PV calls for scrapping of looming subsidy cap

Europe's top solar market is approaching a watershed moment, with capacity nearing a legal threshold where subsidies would need to be withdrawn. German PV association BSW Solar called earlier this year for the scrapping of a subsidy cap that will apply once installed capacity – today surpassing 47GW – hits the 52GW mark. The milestone, BSW Solar warned, could be reached as early as next year. Carsten Körnig, managing director of the association, urged MPs to take the "right course" as he noted their failure so far to update renewable legislation.

France

Ground-mounted PV auction set to boost France's capacity by 10%

A major PV auction held by France in August is set to boost the country's solar capacity by 10%, with 107 developers reaping 858MW worth of contracts evenly spread across the country. The tender, the sixth and final of a government ground-mounted programme, produced average bid prices of €64/MWh (US$71) and awarded 76.1MW of the 858MW total to Engie projects. The auction brings France closer to its target to boost PV capacity from 9.1GW today to 35.6GW-44.5GW in nine years.

UK

UK post-subsidy solar pipeline swells to 5GW

A flurry of activity in H1 2019 saw the UK's post-subsidy solar pipeline surge from 3.34GW to 5.16GW, according to the UK Large-Scale Solar Farms: The Post-Subsidy Prospect List report. The analysis, released within days of Boris Johnson's rise to prime minister this summer, identified 60 new solar farms – 1.8GW in additional capacity all in all – emerging so far this year. Key drivers of the UK momentum included cheaper modules and power rating improvements, according to the study.

The Netherlands

Grid bottlenecks push Netherlands to renewable subsidy restrictions

Dutch PV projects opting for subsidies this autumn will need to secure a preliminary green-light from network operators under new government plans, meant to alleviate grid congestion. Renewable applicants for the Netherlands' SDE+ feed-in premium

programme will have to formally request connection points and produce documents showing capacity exists for their projects, Economy and Climate minister Eric Wiebes announced over the summer. In a letter to Dutch MPs, the top official singled out PV as a congestion driver, noting that its shorter construction timeframes make it harder to predict and adjust to the pace of installations.

Inverter Makers

ABB's net income plummets after solar inverter pull-out

Swiss group ABB posted a 91% plunge in quarterly net income figures this year after paying US$470 million for a buyer to take on its solar inverter business. The drop in the Q2 2019 numbers – reported even as ABB's orders and revenues grew – followed its move in July to offload its liability-ridden solar inverter unit to FIMER, an Italian group that also manufactures the devices. Contacted by *PV Tech*, the firm described the inverter business as a "drag" for margins and said its declining revenues reflects "falling demand globally" for these devices, coupled with price pressures from China.

Credit: ABB Group

The inverter unit had been a "drag" on broader division margins, ABB said

AMERICAS

Trade Tariffs

Bifacial panels get a pass on Section 201 trade tariffs

Bifacial solar modules were exempted from President Trump's trade tariffs. Modules imported from all the major producing countries are levied at 25% currently, falling to 20% in February next year under the Section 201 measures. A statement by the US trade representative in June confirmed that the exemption would be entered on the Federal Register on Thursday. Many Chinese manufacturers face both anti-dumping duties and the Section 201 levies. Between January and September 2018, only 46MW of modules were imported from mainland China to the US. The latest twist creates a route to market for China-sourced modules into the US. More on this story on p.48.

Credit: Trina Solar

Imports from the Chinese mainland to the US have collapsed in recent years.

Tesla

Walmart pins store fires on Tesla solar installs in lawsuit

Walmart linked a string of store fires in recent years to Tesla's alleged mismanagement of solar panel installation and maintenance, taking Elon Musk's outfit to court. A lawsuit from the US retail colossus demands damages from Tesla and the full removal of its solar installs, amid claims that the company's "systemic, widespread failures" were the culprit of a series of rooftop blazes over the past decade. "To state the obvious, properly designed, installed, inspected, and maintained solar systems do not spontaneously combust, and the occurrence of multiple fires involving Tesla's solar systems is but one unmistakable sign of negligence by Tesla," reads Walmart's lawsuit. Shortly after the papers were filed the two companies said they were looking for an amicable, out of court, solution.

Tesla's solar installations hit new low as energy storage hits new high

In reporting second quarter 2019 financial results, Tesla's solar installations reached a new record low, while its 'Powerwall' and 'Powerpack' energy storage products set a new deployment record. Tesla's retrofit solar installations plummeted to only 29MW in the second quarter of 2019, down from 47MW in the previous quarter, then a new low for the company. In stark contrast, Tesla reported that it's Powerwall and Powerpack deployments increase by 81% in the second quarter of 2019, achieving a record 415MWh. This comes after being capacity constrained at Gigafactory 1 through 2018 and a complete stop in production allocation of energy storage products to meet EV Model 3 demand.

Brazil

Bolsonaro clears Brazilian solar scheme at floating plant launch

Jair Bolsonaro has given the green light to a new solar scheme in Brazil's northeast, marking its launch as he attended the opening of a separate floating project. In early August, the president authorised ministers to launch an auction programme for solar to power a major water transfer project. The programme will have PV panels supply the power needed to gravity-pump water from the São Francisco river to drier, poorer northeast areas, mitigating annual electricity costs that could otherwise reach an annual BRL300 million (US$79.5 million). The São Francisco River Integration Project – PISF, in its Portuguese acronym – will pump water along 477 kilometres of channels and aqueducts to bolster the supply of 12 million people in drought-stricken states.

Chile

Chile projects progress continues with fresh finance and construction starts

Sonnedix marked the launch of construction works for a large-scale solar installation in Chile's Atacama desert, with a view to power up the plant late next year. Regional authorities and executives from the IPP including CEO Axel Thiemann attended the ground-breaking ceremony of 171MW Atacama Solar, in the Pica district. Construction, Sonnedix explained, is set to directly create 400 jobs and see the plant become commercially active by December 2020. Financing is being lined up for Chile to deliver a colossal solar-plus-storage installation in the Atacama desert, paving the way for construction to start next year. In other news, the Green Climate Fund (GCF) agreed to allocate US$60 million in fresh

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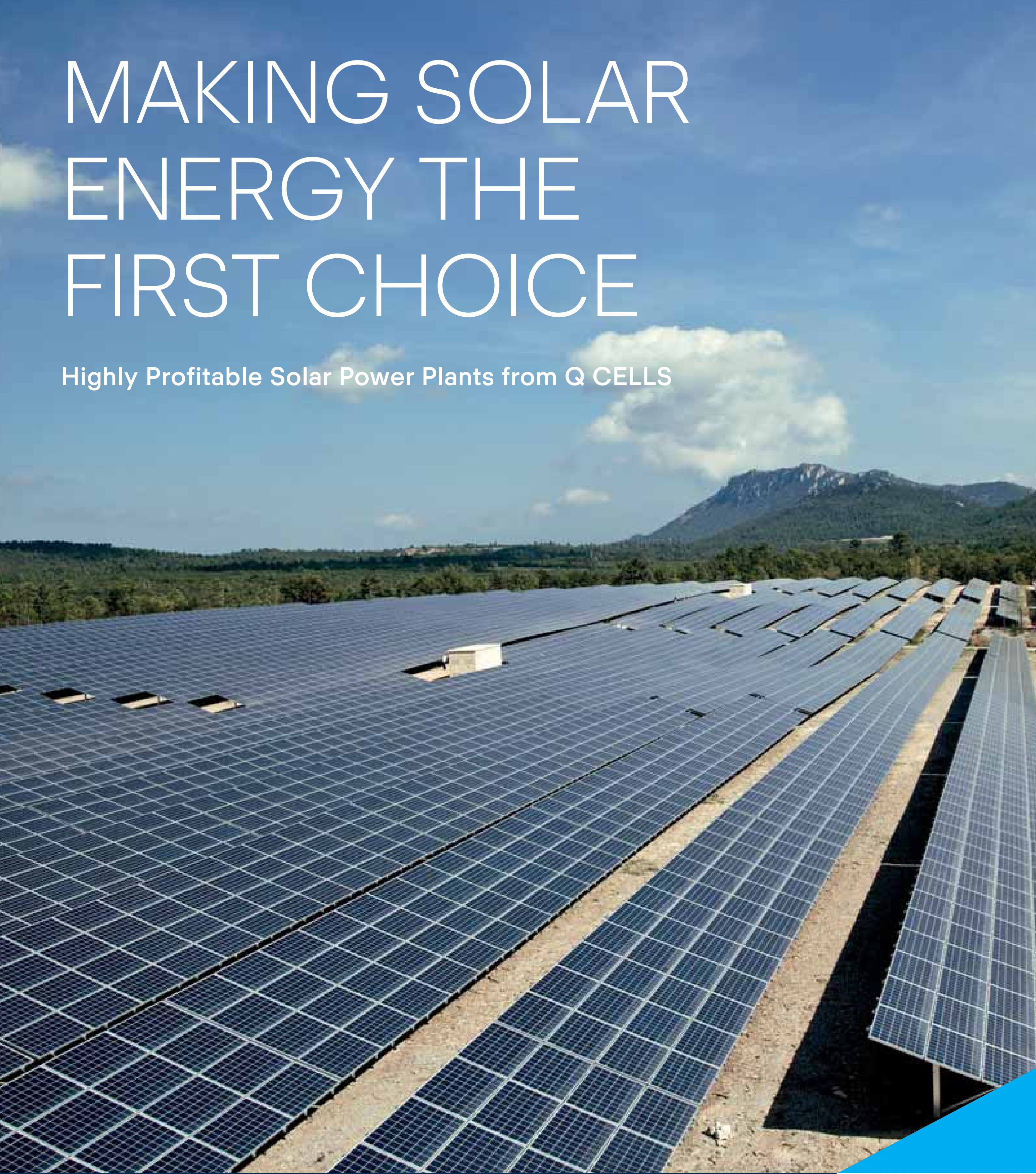

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funding to the Espejo de Tarapacá project, slated for construction at a site near the Pacific coast. The scheme, the work of Chilean renewable developer Valhalla, is designed to deliver a 561MW solar PV plant alongside a 300MW pumped hydro storage system. The overall project is set to cost US$1.094 billion. Elsewhere, Natixis and ARCO 3 SpA have closed senior facilities totalling US$69.1 million for a portfolio of solar PV plants in Chile, with up to 70MW of generation capacity.

Credit: Sonnedix

(L to R): Carlos Guinand, Chairman of Sonnedix; Iván Infante Chacón, Mayor of Pica; Miguel Angel Quezada, Regional Mayor of Tarapacá; and Axel Thiemann, CEO of Sonnedix.

Abu Dhabi

Abu Dhabi's 1.17GW Sweihan marks commercial launch

One of the largest single-site solar installations ever to be completed worldwide has started operations, less than three years after construction contracts were awarded. With 1.177GW in installed capacity, the Noor Abu Dhabi PV park marked its commercial launch in the United Arab Emirates (UAE) on 30 April, Marubeni Corporation said today. The Japanese conglomerate was part of the three-firm consortium hired in 2016 to build the plant, together with JinkoSolar and the Abu Dhabi Power Corporation (AD Power). The trio, which prevailed three years ago with a bid of US$0.0242/kWh, remain owners of the PV park. At 60%, AD Power's share outstrips Marubeni's and JinkoSolar's (20% each).

Credit: Jinko Solar

The Noor Abu Dhabi project.

US policy

Close to 1,000 solar companies push for extension of US ITC

Close to 1,000 companies from across the US solar industry supply chain sent a letter to Congress calling for the extension of the Section 48 and Section 25D solar investment tax credits (ITC). The ITC was passed by a Republican-controlled Congress in the 2005 Energy Policy Act and enacted by George W. Bush. It was extended in 2015 with bipartisan support. Abigail Ross Hopper, president and CEO of the Solar Energy Industries Association (SEIA), said: "If you want to show a commitment to addressing climate change, you extend the solar ITC."

Cluster of states offer boost for solar

A group of states provided a welcome shot in the arm for US solar with a variety of proposals. The Tennessee Valley Authority approved its long-term energy plan which includes 14GW of solar in the next 20 years. North Carolina removed a number of regulatory hurdles for solar including clearing a path for more community projects. Wisconsin governor Tony Evers meanwhile set the state on a path to zero-carbon energy by 2050. In the more immediate term, Arizona issued a tender for 400MW of solar and wind power.

MIDDLE EAST & AFRICA

Solar-plus-storage

USTDA backs 150MW solar-plus-wind-plus-storage project in Zambia

The US Trade and Development Agency (USTDA) has agreed to finance a feasibility study for a 150MW hybrid solar, wind and battery plant in northern Zambia. The money was granted by the independent agency to the Zambian subsidiary of Upepo Energy Partners, a five-year-old firm that develops renewable energy projects across East Africa. If built, the project will be one of the first hybrid renewable energy projects in the country and provide grid support to northern Zambia.

Investigated former Eskom boss to deploy solar-plus-storage in Zimbabwe

A controversial figure in South Africa's energy sector has been authorised to develop solar-plus-storage in Zimbabwe, only a year after a probe saw him suspended from Eskom. On Saturday, Matshela Koko took to social media to hail the decision by Zimbabwe's energy regulator ZERA to allow a firm he owns to deploy a major hybrid project in the country. According to the ZERA notice Koko shared on Twitter, Matshela Energy will build, own and run a 100MW plant in Gwanda, a two-hour drive north from Zimbabwe's border with South Africa. The 25-year licence from ZERA, Koko explained, also covers the potential roll-out of a 240MWh battery energy storage system. The new professional venture follows a controversial past two years for the engineer, who in 2017 and 2018 was suspended as acting group chief executive of South Africa's state-owned utility Eskom.

Africa

Botswana, Cameroon issue tender, sign contracts for combined 125MW of PV capacity

The African countries of Botswana and Cameroon have taken steps to add a combined 125MW of installed PV capacity to their respective national grids. Botswana utility company Botswana Power Corp has sent out a request for qualification (RFQ) to interested companies and other parties for the development of 100MW of PV capacity, split into two seperate 50MW solar projects. The RFQ will look to identify suitable independent power producers for the two sites, which Botswana Power Corp would buy power from under a long-term PPA. Meanwhile, Eneo, a power utility company in Cameroon, has signed off on a memorandum of understanding (MoU) with a consortium of renewable energy developers for the development of two PV projects with a total installed capacity of 25MW. This consortium includes Scatec Solar, Izuba Energy and Sphynx Energy.

Scatec Solar links Mozambique's utility-scale PV frontrunner

Scatec Solar has powered up what it claims is Mozambique's first utility-scale solar project, signalling the end of a development process going back at least to 2016. The Norwegian group said this week its 40MW scheme near Mocuba, a city in the country's north, is now operational after being connected to the grid. The commercial launch comes almost three years after the project inked a 25-year power purchase agreement (PPA) with Mozambique's state-run utility EDM. Last March, Scatec Solar explained Mocuba would cost around US$76 million, US$55 million of which was project debt raised that month from the World Bank's IFC and Investec's African fund EAIF.

Engie's 60MW Scaling Solar duo hits financial close in Senegal

A 60MW duo touted as a success marker for the Scaling Solar programme is ready for construction in Senegal after reaching financial close. The World Bank's International Finance Corporation (IFC), the European Investment Bank (EIB) and France's Proparco will back two ENGIE projects with €38 million (US$43 million) in senior loans. The schemes – a partnership between Engie, investor Meridiam and Senegal's sovereign wealth fund FONSIS – can now start construction at sites by the West Senegal towns of Kael and Kahone.

Gulf

All systems go for Saudi Arabia's top ground-mounted PV plant

A ground-mounted solar project billed as Saudi Arabia's largest to date has reached the finish line, and is now set to power the operations of a food and beverage conglomerate. Listed firm Almarai Company announced this week the completion of 15MW Al Kharj Solar project, built at costs of SAR44.4 million (around US$12 million). The corporate, specialised in food and drinks manufacturing and distribution, said the 44,000-panel installation will generate 28GWh of solar power every year.

Abu Dhabi shortlists 24 firms for 2GW solar plant

Abu Dhabi utility Emirates Water and Electricity Company (EWEC) shortlisted 24 out of the 48 international and local developers that expressed interest in its latest 2GW solar venture to be located at Al Dhafra, according to Reuters. The tender, first announced back in February, forms part of a series of projects approved by the higher Committee for the Water and Electricity Sector in Abu Dhabi. The 2GW installation is expected to achieve commercial operations during the first quarter of 2022. A release from EWEC highlighted that this project will be nearly double the size of its other major plant, the 1,177MW Noor Abu Dhabi at Sweihan completed in April. Once completed Abu Dhabi's total deployed solar capacity will hit 3.2GW. Successful bidders will hold 40% equity in the project, with the remaining stake held by local entities.

China market bonanza

China's new FiT scheme to support nearly 22GW

China's National Energy Administration (NEA) approved nearly 22GW of solar capacity for the country's new feed-in tariffs scheme, announced in mid-July. According to Asia Europe Clean Energy Advisory (AECEA) this could see 38-42GW installed in the country this year. The lowest bid came in at RMB0.2795/kWh, just over US$0.04. The long-awaited new FiT system awards capacity through a reverse auction with interested parties bidding for a premium to be paid on top of regional benchmark electricity prices. It replaces the old scheme halted suddenly in May last year, the so-called 531 New Deal. While the estimates for 2019 would still fall short of last year's 44GW, it is a vast improvement on some expectations earlier in the year. Q1 installations were down 46% year-on-year. The successful bids included 366 ground-mounted utility-scale projects with a combined capacity of 18.12GW, therefore accounting for the majority (79.5%) of projects. A total of 3,082 self-generation/self-consumption/excess capacity projects were accepted with a combined capacity of 4.10GW and accounted for 18% of the total.

Credit: United PV

China's 2019 installs are set to be heavily back-loaded into the second half of the year.

Oman launches tender for 1.1GW

The Oman Power and Water Procurement Company SAOC (OPWP) kicked off on Tuesday the tendering process for two independent power projects (IPP), with a combined output of 1.1GW. The Manah Solar I IPP solar facility and the Manah Solar II IPP are planned 95 miles southwest of Oman's capital Muscat. They will each have a capacity of between 500MW and 600MW and are expected to be commissioned in 2022 and 2023.

ASIA-PACIFIC

Subsidy-free PV a reality across China

Solar could be rolled out on buildings across all of China's major urban centres at competitive prices without the need for subsidies, according to a new study published in Nature Energy. Researchers from Stockholm's KTH Royal Institute of Technology released what they claim is among the first sweeping reviews to date of the grid parity state-of-play for Chinese solar. Where previous reports predicted the milestone – attained when PV prices drop to grid-wide averages – would take decades to arrive for Chinese solar, the new analysis claims the threshold has already been crossed on the distributed end. Researchers modelled costs of subsidy-free commercial and industrial (C&I) solar systems across 344 prefecture-level Chinese cities and found prices-per-kWh paid by users – a bill including energy- but also transmission- and distribution-related expenses – would already match grid averages for all.

India

India prevails over US in long-running trade dispute

India has succeeded in having US solar incentives declared in breach of World Trade Organisation (WTO) rules, signalling Washington's defeat after nearly three years of dispute. A WTO panel found solar tax incentives across seven US states infringed India's rights under the General Agreement on Tariffs and Trade (GATT) of 1994, in a decision made public as both countries joined G20 talks in late June. According to the report, 10 schemes passed in California, Connecticut, Delaware, Michigan, Minnesota, Montana and Washington state meant Indian solar panel imports were unfavourably treated versus their US counterparts, in breach of GATT rules. The WTO twist sees India triumph in a dispute it brought before the intergovernmental body in September 2016. The current panel was formed in April 2018, after conciliatory India-US talks convened in 2017 failed to settle the conflict.

India's pipeline boom

India had its highest ever capacity of solar projects allocated or at various stages of development by the end of Q1 2019, suggesting a significant pick-up in installation activity over the next two years, according to a report from consultancy firm Bridge to India. In the 'India Solar Compass 2019 Q1' report, however, the consultancy said that a surge in tender issuances is still not being matched by actual project allocations. During the first quarter of the year, 19 new utility-scale solar tenders with a combined capacity of 15,733MW were issued (up 2% from Q4 2018), but only 3,697MW of capacity was successfully allocated. Nevertheless, the South Asian nation's PV project pipeline stood at a record 18,438MW as of 31 March 2019. While deployment is set to increase, the industry is facing growing troubles with land acquisition, network connectivity, delayed payments and tender cancellations, said the report. Meanwhile, the commercial and industrial (C&I) segment has been hampered by policy reversals in rooftop solar and open access regulations.

Australia

Authorities back 10GW+ solar colossus

Australian authorities have rallied behind what is arguably the largest solar-plus-storage project to be conceived in the world's history. Northern Territory first minister Michael Gunner confirmed his government has granted major project status to a scheme mixing 10GW of solar with 20-30GWh of storage. Designed with costs of AU$20 billion (US$14 billion) in mind, the project is slated for construction in Tennant Creek, a town in central Northern Australia. The scheme is the brainchild of Singapore's SunCable, which wants to use it to shore up the Asian state-city's power system and limit its over-reliance on natural gas imports. The developer intends to set up a 3,800 km high-voltage direct current submarine cable to transfer most of the installation's output to Singapore, where it could cover 20% of power needs.

Fix state support 'crisis', Aussie PV industry says

Australian associations have joined opposition politicians in urging Victoria State to lift a monthly cap on solar incentives, after claims that August's quota was fully booked within two hours. Operators shared dismay at today's swift allocation of monthly solar rebates, with the Clean Energy Council and the Smart Energy Council claiming they ran out in 106 and 90 minutes, respectively. The incentives – covering up to AU$2,225 (US$1,566) per solar panel system – were halted by the Labor government in April 2019 and re-instated three months later, albeit with a monthly cap. The July quota of 3,333 was snapped up quickly after their release, sparking an industry rally in state capital Melbourne last week to protest against the impacts from rebate rationing.

Southeast Asia

Philippines turns on 200kW floating solar project

A 200kW floating solar project is now live above one of the Philippines' largest reservoirs. Norwegian floating solar technology provider Ocean Sun partnered with Chinese solar manufacturer GCL-SI in June to build the floating solar system in the 1,170-hectare Magat reservoir, found 220 miles north of capital Manila on the island of Luzon. It is the Philippines-based renewable energy group SN Aboitiz Power-Magat's (SNAP) first non-hydro project. The floating system will undergo a 10-month stress-test to ensure it can withstand inflows and typhoons and will initially service house load requirements for SNAP's Magat hydroelectric power plant. The dam currently generates 360MW of hydro-electricity.

Credit: GCL System Integration

The Ocean Sun system in the Philippines.

Sunseap, InfraCo Asia complete 168MW solar plant in Vietnam

Singapore-based clean energy firm Sunseap International and partner InfraCo Asia commissioned a 168MW solar farm in Ninh Thuan province, on the south-central coast of Vietnam. As one of the country's largest PV projects to date, it will power the equivalent of roughly 192,000 homes under a 20-year solar power purchase agreement (PPA), the signing of which was announced last year. The plant was completed ahead of schedule and in time to receive a feed-in tariff (FiT) of US$9.35 cents per unit under the 30 June deadline. The project, which is majority-owned by Sunseap International, offered employment opportunities to more than 2,000 workers.

WoodMac: APAC renewables to outcompete coal within eight years

Indian and Australian solar will spearhead a grid parity shift set to take hold of Asia-Pacific renewables within less than a decade, according to Wood Mackenzie. Renewables' levelised cost of energy (LCOEs) across the region's top 12 markets remains 29% higher than coal-fired power but the gap will vanish by 2027, the firm predicted on Monday. By 2030, the new analysis estimated, solar and wind will actually be 17% cheaper on average than any fossil fuels across the 12-strong group, spanning India, Australia, China and Japan. Wood Mackenzie research director Alex Whitworth said the shift will drive a major jump in these markets' current renewable share of 6%, creating "opportunities" but also "disruption".

Product reviews

Modules | Q CELLS Q.PEAK DUO BLK-G6+ panels to be assembled in US with 345Wp performance

Product Outline: Q CELLS will launch its new solar module, the Q.PEAK DUO BLK-G6+, into the US market in September 2019. The module includes half-cut larger cells which boast dimensions of 161.70mm (full wafer), as opposed to the 156.75 mm cell dimensions found in its G5 range, boosting power output by 6% to 345Wp. The product will be is assembled in America at Q CELLS' affiliate's module assembly plant in Dalton, Georgia.

Problem: The US residential market is increasingly shifting to high-efficiency monocrystalline panels that provide the lowest LCOE and meet prosumer requirements for reliability and aesthetics.

Solution: The Q.PEAK DUO BLK-G6+ solar module is designed specifically for the rooftop solar market. The product also boasts optimised shading behaviour, which is a vital feature for many rooftop installations. The upper and lower sections of the module can operate independently, reducing the impact of shading and thereby increasing energy yields. With the contribution of this function, the Q.PEAK DUO BLK-G6+ can generate much more power, especially on residential as well as commercial and industrial (C&I) rooftops.

Applications: US Residential and C&I rooftop markets.

Platform: The Q.PEAK DUO BLK-G6+ also offers long-term reliability with a 25-year product warranty and one of the lowest degradation rates in the industry, which guarantees 85% initial performance in the 25th year.

Availability: September 2019 onwards.

Modules | Trina Solar launches 425Wp bifacial TOPCon panel

Product Outline: Trina Solar has launched a new high-performance module series using large-area n-Type monocrystalline TOPCon (Tunnel Oxide Passivated Contact) cell technology in both half-cut 144 (72-cell) and 120 half-cut (60-cell) configurations. The i-TOPCon double-glass bifacial modules can achieve performance of 425Wp with cells of 20.7% conversion efficiency.

Problem: High-performance modules are required in a post-subsidy, grid-parity environment to reduce overall system levelised cost of electricity (LCOE). Bifacial modules offer greater overall power output, while n-type mono cell technology offers lower degradation and higher reliability.

Solution: The new i-TOPCon double glass PV modules integrate n-type bifacial i-(Industrial) TOPCon cells with at least 80% bifaciality. The modules come with multi-busbar (MBB) design, full square large-area n-type monocrystalline cells, dual-sided and half-cut technologies. The highly efficient modules feature a lower temperature coefficient and low light induced degradation (LID), which is less than 1%, according to the company. The modules also provide an extra 5-30% power generation from the rear side, and feature a 30-year linear power warranty.

Applications: The half-cut 144 (72-cell) glass/glass module is designed for ground-mounted utility-scale PV power plants as well as agro-photovoltaics and expressway sound barrier projects. The 120 half-cut (60-cell) configuration module can be used in utility-scale PV power plants using tracker systems.

Platform: The half-cut 144 (72-cell) layout includes module dimensions of 2031 x 1011 x 30mm and weighs 26.4kg. The 120 half-cut (60-cell) configuration has module dimensions of 1705 x 1011 x 30mm and weighs 22.0kg.

Availability: Available since June 2019.

Design | DNV GL's PV power plant modelling software tackles complex terrain issues

Product Outline: DNV GL has developed software for modelling, design and analysis of solar photovoltaic (PV) plants that can accurately and efficiently handle the demands of layouts in increasingly complex terrain.

Problem: As the demand for solar energy increases, solar plant design are becoming more challenging as the terrain becomes more complex. This will require PV plant design software that can perform more reliable modelling for accurate energy calculations and submodule electrical mismatch.

Solution: SolarFarmer software provides unique models designed by engineers based on decades of engineering experience in the solar industry. It can be used for conceptual and detailed design and analysis for solar PV plants and is an efficient and traceable method for modelling in complex terrain.

Applications: Design and analysis of development of solar PV plants, from conceptual model to detailed solar plant design.

Platform: SolarFarmer software combines thoroughly validated PV simulation algorithms with a user-friendly, modern user interface allowing quick configuration of PV plant designs and simulation of PV layouts. The PV plant design software has a full 3D shading and calculation model, submodule electrical mismatch and enables sub-hourly energy assessments compared with hourly energy assessment that can lead to errors such under-estimating inverter clipping losses during cloud coverage.

Availability: Available since May 2019.

Modules | GCL System Integration's cast-mono panel tops 420Wp power output

Product Outline: GCL System Integration has launched a new 420Wp ultra-high efficiency cast-mono panel series. The cast mono panels combine mono-crystalline PERC (Passivated Emitter Rear Cell) technology with multi-crystalline ingot casting technology to reach a panel efficiency of up to 19.4%.

Problem: Striving for lower costs and higher efficiency has been a common concern and key objective of the PV industry. Increasing wafer sizes, while adopting half-cut or shingled cells to reduce resistivity are low-cost routes to higher wattage panels.

Solution: The module adopts 158.75mm x 158.75mm cells, which have a low degradation rate thanks to their low oxygen content – 40 percentage points lower than monocrystalline, according to the company. The wafer resistivity distribution is also more concentrated, translating to higher performance. In addition, the cost mono module increases efficiency by providing 2% more space to absorb light than standard-sized mono PERC modules.

Applications: Utility-scale, commercial and industrial and residential markets.

Platform: The cells in the new panel have an average efficiency of 21.4% and are made of high-quality silicon wafer and polysilicon materials produced by GCL-Poly. By adopting the ingot casting technology through methods such as thermal field optimisation and the addition of seed crystal, the final product comes out with low electric resistance rate, high purity, low oxygen content, better structure and reduced costs compare to mono wafers. When integrated with other advanced technologies such as Multi-Busbar technology (MBB) and white EVA, the GCL cast mono module has a lower temperature coefficient, better performance in power generation and less vulnerability to light-induced degradation.

Availability: Available since June 2019.

Modules | JinkoSolar's 'Swan' bifacial panel saves weight with transparent backsheet

Product Outline: JinkoSolar has introduced a new bifacial PV panel with new 'DuPont Clear' 'Tedlar'-based backsheet. The 'Swan' bifacial panel can achieve power output of up to 400W on the front side and up to 20% energy gain from the rear side.

Problem: The majority of bifacial panels come in a glass/glass format and have a weight penalty that impacts transportation and installation costs.

Solution: Leveraging the transparent backsheet, Swan bifacial panels can produce the same power output levels and rear-side energy gain as dual-glass bifacial modules, weigh less, are easier to install and include a 30-year power warranty. In addition, they can generate more system cost savings due to their lower weight and decreased cost of installation and mounting. The panel weight is 19.5kg in 60-cell (120 half-cut) format, compared to 26.8kg in a 60-cell (120 half-cut) glass/glass configuration.

Applications: Utility-scale ground-mounted and commercial & industrial rooftop markets.

Platform: The 'Swan' bifacial panel uses Mono PERC (Passivated Emitter Rear Cell technology with wafer/cell size of 158.75×158.75mm. The Swan panels come in a 60-cell (120 half-cut) and 72-cell (144 half-cut) format. The 144 cell panel dimensions are 2031×1008×40mm. The 'Swan' bifacial panel comes with a 12 year product warranty, 30 year linear power warranty and 0.55% annual degradation over 30 years.

Availability: Available since May 2019.

Modules | Jinergy launches 72-cell 450Wp heterojunction bifacial panel

Product Outline: Jinneng Clean Energy Technology has released its 450Wp 72-cell heterojunction (HJT) panel that includes excellent low-light performance and ultra-low temperature coefficient and degradation.

Problem: High-performance bifacial panels offer subsidy-free LCOE metrics that have the ability to drive utility-scale PV power plants to become the most competitive renewable energy source.

Solution: Jinergy's HJT module, JNHM72-450, is claimed to offer an increase in overall power generation of 44% when compared to regular polycrystalline panels. HJT modules have excellent performance in weak light, a temperature coefficient of -0.28%/, and ultra-low degradation with n-type silicon wafer. Moreover, power generation is increased by 8-20% in different application because of bifacial cell structure design. Compared with regular high-efficiency modules, the power generated in 25 years could be increased by 20%, and power generation per unit area could be increased by more than 40%.

Applications: Utility-scale ground-mounted and commercial and industrial rooftop markets.

Platform: With the continuous optimisation of technology and process, Jinergy HJT cell average mass production efficiency reached 23.79%, and efficiency of new experimental cells reached 24.73%. Tested by TUV Rheinland, the module efficiency of Jinergy's HJT modules has reached 21.9% and bifaciality has reached 93%. Front-side power output of 72-cell HJT module has reached 406.6W without using technologies such as large wafers and half-cut cells. The panel is compatible with 1,500V system voltage to reduce construction cost per watt and is available in 60-cell and 72-cell formats.

Availability: Available since June 2019.

Product reviews

Modules | LONGi Solar's Hi-MO 4 bifacial module offers 430Wp front side performance

Product Outline: LONGi Solar has launched its advanced large-area mono-wafer next-generation PERC (Passivated Emitter Rear Cell) technology incorporating half-cut cells and six busbars, with cell efficiency reaching 22.5%. The Hi-MO4 bifacial module series come with 430Wp front side performance.

Problem: Upstream of module production, silicon wafers account for 30-40% of the cost of the module. Hence, advances in silicon wafers technology are instrumental in cost reductions and creating more efficient products.

Solution: Hi-MO 4 panels are the first to deploy large-area M6 (166mm x 166mm) monocrys-

talline wafers. Hi-MO 4 modules configured with 72 cells can achieve 430Wp performance. The upgrade to M6 silicon wafer specification allows a larger light-capture area which increases the power of cells and modules while reducing the manufacturing cost per watt. At a cost-per-watt comparison, M6 is equivalent to M2 and increases the output power by 8.8% vs M2. With M6, the procurement cost of silicon wafers is reduced by 4% per watt.

Applications: Utility-scale and commercial and industrial rooftop markets.

Platform: Hi-MO4 deploys upgraded PERC technology with six busbars and offers cell efficiency reaching 22.5%. While the front-side power Hi-MO3 is 380W (72 cells), Hi-MO4 increases this to as much as 430Wp. BOS cost can be reduced by approximately 7%, and LCOE by 1.4%. Combined with tracking systems, the LCOE can be further reduced. Hi-MO4 is compatible with a number of single-axis tracker systems, including NexTracker. Module dimensions are 1791x1052x30mm. The glass/glass format weighs 24kg with 2mm tempered glass front and rear.

Availability: Available since May 2019.

Operations and maintenance | Raycatch uses artificial intelligence technology for PV power plant O&M

Product Outline: Raycatch has introduced 'DeepSolar 2.0,' a fully automated, AI-based diagnostic software program for cost-optimised maintenance and monitoring of photovoltaic power plants. Raycatch, which is backed by BayWa r.e., developed the next-generation of DeepSolar, its AI-based Software as a Service (SaaS) solution.

Problem: PV project owners require increasingly sophisticated tools to sift and evaluate large volumes operational data from plants, identify faults and make decisions on how best to maintain their assets.

Solution: DeepSolar is a diagnostic software program for cost-optimised maintenance of

PV power plants. The AI-based algorithm uses data generated by existing monitoring systems to enable optimisation of O&M – replacing interval-based maintenance with a cost-efficient responsive approach that is designed to analyse and perform accurate diagnostics on the high influx of complex data from PV systems.

Applications: PV power plant O&M.

Platform: DeepSolar 2.0 comprises features that make it possible to successfully identify and break down all components affecting solar plant performance – and group them back together to create an extensive, coherent picture. The software supports solar plant owners by providing them with comprehensive ROI information and data-driven operational insights. In addition, the diagnostic system can identify the sources behind technical issues, suggest solutions, evaluate costs and make prioritised recommendations based on plant owners' respective needs.

Availability: Currently available.

Modules | REC Group's 'Alpha' series PV panel offers power output of up to 380Wp

Product Outline: REC Group has unveiled the 'Alpha' series PV panel using n-type heterojunction half-cut cells with power output of up to 380 watt-peak (Wp).

Problem: Reducing the balance of system (BoS) costs for residential rooftop markets is key to continued adoption. High-performance panels are the best option, especially when there is limited rooftop space.

Solution: The Alpha is built around 120 half-cut heterojunction cells (HJT) and advanced connection technology, designed by engineering experts from Germany and Singapore. With

HJT, REC combines the benefits of crystalline silicon solar cells with those of thin-film technologies for much higher efficiency and energy yield, even at higher temperatures. The REC Alpha Series offers 20% more power from the same area and the same number of panels. For a 20kW solar installation at a multi-apartment property, for example, 70 panels with 300Wp, or an area of 140m2, would be required. But with the 380Wp of the REC Alpha Series, the building would only need 50 modules, or roughly 100m^2.

Applications: Residential rooftops.

Platform: The Alpha panel uses 120 half-cut HJT cells, with six strings of 20 cells in series. It features 3.2mm solar glass with anti-reflection surface treatment and backsheet. Two versions are available: with white backsheet (up to 380Wp), and as a full-black panel (up to 375Wp). Panel dimensions are 1,721 x 1,016 x 30mm and weight, 19.5kg.

Availability: The Alpha Series is scheduled to go into production in Q4, 2019.

Modules | Risen Energy's JÄGER series panels hit 340Wp

Product Outline: Risen Energy's JÄGER series PV panels using its proprietary cast-mono 5BB cell have achieved an efficiency of 22.05% while its MBB monocrystalline cell has realised a maximum conversion efficiency of 23.08% and an average efficiency of 22.73%.

Problem: The need to reduce the levelised cost of energy (LCOE) continues to drive cell and module conversion efficiencies, while achieving cost effective manufacturing at scale. The adoption of large-area high-purity wafers and multi-cut cell configuration and bifacial cells further increase efficiencies.

Solution: The cells are ALD-AlOx passivated PERC (Passivated Emitter Rear Cell) technology with Light Reflecting Film (LRF) ribbon as well hi-spec white EVA and narrow distance between connected cells to reduce cell to module (CTM) losses. The cast-mono five-busbar cell uses a series of efficiency enhancement technologies including double-sided passivation, antireflective films, electro-injection passivation and slurry improvement. This is the first time that a cast-mono 5BB cell has exceeded 22% in efficiency. Compared with the 5BB cell, the MBB monocrystalline cell features a more optimised metallised contact technology, which effectively reduces the shading area, enhancing the ability to collect carriers while reducing the incidence of cracks and contributing to a higher conversion efficiency. At the same time, a further cost reduction is realised with decreased use of silver slurry.

Applications: Utility-scale, commercial & Industrial and residential markets.

Platform: JÄGER series PV panels use 158.75mm x 158.75mm 5BB PERC cells in a 120 half-cut format. Panel dimensions are 1689 x 996 x 35mm. Front side glass uses tempered ARC with a thickness of 3.2mm.

Availability: Currently available.

Modules | Seraphim's high-performance 'Blade Bifacial' panel has reduced hot spot potential

Product Outline: Jiangsu Seraphim Solar System Co has recently rolled out an new bifacial solar panel, 'Blade Bifacial'. According to Seraphim, the new product integrates industry-leading half-cell technology and latest bifacial PERC cell technology, allowing it to have such features as low internal power loss, reduced hot spot potential, higher power output and improved reliability.

Problem: Compared to traditional modules, half-cell modules have lower current and series resistance, which can minimise mismatch losses, internal power losses and shadow effects.

Solution: The integration of the half-cell technology and the bifacial PERC cell technology is an important route to develop the PV module technology and adapt to the needs of the PV industry. The module yields up to 30% more energy from back side power generation, depending on the albedo/reflectivity of each individual project site.

Applications: Utility-scale and commercial & industrial rooftops. Available in 60 cell 120 half-cut and 72 (144 half-cut cell) formats.

Platform: The Seraphim Blade Bifacial module is much lighter as it uses the 2.0 mm double AR coating tempered glass, instead of the 2.5 mm glass used by most PV manufacturers. It features an IP68 protection class junction box with multiple diodes integrated to reduce hotspot risk. Unobstructed view of cells improves safety and power generation. The Blade Bifacial panel comes with and extended product warranty of 15 years.

Availability: Available since May 2019.

Inverter | Sungrow's SG250HX 1500V string inverter is optimised for bifacial modules and tracker systems

Product Outline: Sungrow Power Supply has introduced the SG250HX, the world's most powerful 1500Vdc string inverter, which is optimised for hilly utility-scale installations and designed for bifacial modules and tracker systems. The system, resilient to harsh conditions, is characterised by 12 MPPTs, maximum efficiency of 99%, anti-PID, IP66 and C5 protection and allows for up to 6.3MW block design, enabling high yields.

Problem: The application of new technologies such as bifacial modules and tracker systems are intended to significantly reduce LCOE metrics in PV power plants. However, these new technologies require advances in PV inverter technology to maximise the IRR. PV inverters also need to adapt to installs in complex environments, such as hilly, coastal or desert areas.

Solution: The global market for large-scale PV installations is shifting to bigger block design to reduce the LCOE. Based on the cost comparison of different capacity block, 6~7MW block enables lowest cost, according to Sungrow. The SG250HX inverter is suitable for any block size between 3MW to 6.3MW and can run at full load for a long time due to component selection and advanced design. Additionally, with 12 MPPTs it can adapt to complex terrain conditions and enables 26A input current per string, perfectly matching bifacial modules. SG250HX also provides reserved power supply and communication interface to the tracker system.

Applications: Utility-scale PV power plants

Platform: Sungrow can supply 6.3MW MV Station which integrates LV switchboard, transformer, RMU, communication device and auxiliary power supply in a 20-ft container. Also, SG250HX and communication device supports PLC (Power Line Communication), which decrease communication cable cost.

Availability: Available since May 2019.

Open season: the next steps for energy storage

Storage | Despite the huge strides energy storage has made, significant hurdles remain before the technology in its many guises can be claimed to have fulfilled its massive potential. Introducing a PV Tech Power energy storage special report, Andy Colthorpe assesses the key successes and ongoing challenges for this indispensable part of the future power system

Credit: Anesco

Large-scale battery sites have been built in regions including the UK (pictured). But are they doing enough and should there be commercial impetus to build more?

The world has watched on as some of its leading regional markets, China, South Korea, Australia, Japan, parts of the US, the UK, and many parts of Europe have raced ahead in deploying energy storage in the last five years, mostly, but not only, lithium-ion batteries. IHS Markit says that the US in 2019 will deploy around 712MW, becoming the world's largest market for grid-connected batteries this year, while another research firm, Wood Mackenzie Power & Renewables, has predicted that 4.3GW could be installed worldwide during 2019.

Record-breaking figures have been reported in the US and other territories such as the UK, year-on-year. Yet from other territories reports come in of interminable delays, of hotly contested jurisdictional rights, the difficulty in overhauling not only the technical design of the grid but the ways in which we think about energy markets too. Everyone seems certain energy storage is a key part of the decarbonised energy system, but no one seems certain when we will be able to breathe a sigh of relief that that place is assured. And of course, there's the question of whether success in these leading markets can be replicated all over the world.

In those leading regions, the rapid rise is happening both in front of and behind the meter, with economic cases that are finally starting to make sense and often – but not always – with specific policy support. And while solar industry investor and commentator Jigar Shah predicted confidently that utilities would try to take ownership of energy storage as much as they could themselves at the beginning of 2018, it seems as though 2019 was the year that this really took shape.

A quick case study of a utility in one of those 'leading regions' is municipal power provider LADWP in California, which over the next few years will deploy enough batteries to cover more storage output and capacity than its existing 1.5GW pumped hydro plant (see box, p.23). We also asked Janice Lin and Jack Chang at consultancy Strategen, itself based in California, to write about the 'challenges in the sun' California faces and some of the initiatives, both private and public, that are seeking to overcome them (see p.32).

Meanwhile in Australia, major utility AGL is now offering rebates of up to AU$7,000 off the cost of residential ESS purchases, as well as a virtual power plant programme which benefits homeowners in some states to the tune of AU$280 credit for a year for enrolling.

They and others are pushing ahead in areas where there may be high electricity prices and high grid congestion, falling feed-in tariffs and favourable tax regimes. Whatever the reason, circumstances have come together to reduce the risk and improve the return of procuring, owning and operating energy storage in some territories.

Fear of missing out

Other utilities in other territories face totally different circumstances, such as Xcel Energy, which operates as a near-monopoly in Colorado, USA. Holding an all-resource, all-technology bid for new capacity a couple of years ago, in addition to picking out wind power projects, the utility also selected three solar-plus-storage projects, Alex Eller, analyst with Navigant Research says.

The utility hasn't done much in the way of standalone storage, because Xcel hasn't yet found "other use cases where storage was economical for distribution upgrade deferral and things like that", Eller says, and so in Colorado, where land is fairly cheap and so is electricity, it's the competitive economics of solar – now dispatchable with the addition of storage – that appeals, rather than storage in its own right. Being a vertically integrated utility, Xcel could later use the batteries at its solar-storage plants, each of which will have in the region of 50MW of batteries, for frequency regulation and other balancing services, but the main impetus is the deployment of renewables to replace fossil fuels.

It is an interesting snapshot of the wider picture across much of the US, Eller says. Many utilities now procure storage alongside solar as a low-cost generation source. Backed with PPAs, they offer the most certainty of use cases for energy storage on the US grid so far. Elsewhere, some standalone storage is deployed increasingly by municipal utilities, which have a certain degree of autonomy – in other US regions such as New England, where the regional Independent System Operator (New England ISO) has also opened up some of its markets to energy storage.

So, even with this seemingly positive picture, where in some areas electric system stakeholders of various kinds and local and even national governments are getting behind energy storage in a big way and in other regions solar-plus-storage makes sense, will it be enough? And if, as we suspect, it might not be, what are the challenges and barriers in the road ahead?

Despite futuristic concepts and design, battery energy storage is about functionality for both grid and end customers.

More to cost reduction than batteries themselves

A lot of emphasis has been placed on the cost of the batteries, which as we all know continue to enjoy a decline. Navigant's Eller has previously predicted a fall to around US$76 per kWh by 2030, rival analyst Logan Goldie-Scott at BloombergNEF conversely says that an "average" lithium-ion battery pack could cost as low as US$62 per kWh by that year.

Beyond the cost of the battery as well, power electronics components could still enjoy improvements in design and lowering of costs, Eller says, with much of that to centre around the standardisation of battery inverters, which the analyst says were "pretty customised" in the past.

One area Eller highlights is the growing interest in DC-coupled storage, explored in more detail in Sara Verbruggen's piece on storage system architecture later in this special report (see p.29). "[That] reduces the cost…because the DC converters are much cheaper than full grid-tied inverters are. So I think that certainly helps bring prices down," Eller says.

On the system side, there's also the reduction in cost of software, but much of this has already been squeezed out, Eller says. Still, software is key in another vital way – the role it plays in complete system integration.

This year, product launches on the global market have included a 2.5MWh containerised solution from Saft and later a 3MWh 'Megapack' from Tesla. Offering more fully integrated, modular, all-in-one units that include the battery management system (BMS) and safety and protection features delivered in a single container from a single vendor can lower costs significantly, Eller says, noting that NEC's Energy Solutions division and Fluence are also now marketing "specific, defined products" to the market. Standardisation within individual vendor's offerings is certainly encouraging, the Navigant analyst says.

In the long term, Eller says storage companies should aim to offer more "plug-and-play" products to utilities, that will be "faster and easier to deploy" than more specialised equipment.

The edge of profitability

Stationary energy storage systems are on the "edge of profitability in many market segments today", we hear in this special edition of the journal from Dr. Kai-Philipp Kairies, Jan Figgener and David Haberschusz of RWTH Aachen University (see p.24).

Yet markets that reward the benefits of energy storage are drastically underdeveloped. Many in the US are looking to the bipartisan ruling FERC Order 841 from the Federal Energy Regulatory Commission, which instructs regional grid operators to open up wholesale markets to the participation of energy storage and is intended to be a game changer for the industry.

Many of the regional ISOs of the US have already responded by drafting their initial plans to comply with the Order. However, says Jennifer L. Key, a FERC lawyer with law firm Steptoe & Johnson LLP, there have been "somewhat surprising legal challenges…from both the state and public power and even parts of the utility industry dealing with jurisdictional fights over storage, between FERC and the states".

A "uniquely American problem", Key says, of dual state and federal regulation, is holding up FERC Order 841 before the details are even put on the table for discussion. A lot of the disagreement essentially stems from "whether FERC or the state should have control over all things wholesale going on on the distribution system because a lot of storage is being connected to the distribution system – as opposed to the transmission system", Key says. "A large swathe" of distribution system companies and state commissions have "filed for an appeal of Order 841 on jurisdictional grounds".

"What's interesting is that you have some states that are fully supportive of storage, that don't mind at all that FERC is taking a lead and you have utilities and distribution system owners who don't care who has jurisdiction; the storage that's coming in, they're dealing with it, they're doing the right thing to get the storage interconnected.

"[Then] you have this whole entire pushback and it's unclear if that's because the states want to control the entry and use of storage," Key says. Whether that is because individual state commissioners believe they could do it better than FERC perhaps, or believe that distributed storage could interfere with operations of their electric system somehow is also unclear, Key adds.


Credit: Wasatch Group/ Sonnen/Rocky Mountain Power

Soleil Lofts, a 600 apartment development in Utah where Sonnen will deploy 12.6MWh of batteries in new homes

Regulation, regulation, regulations

Jennifer Key and others argue that when FERC Order 841 does come to pass, it really will be a game changer partly because "it is compelling the organised markets in the US to develop and make sure that their systems whether it's their software, or their market systems, have a place for energy storage which compensates".

"One of the issues [Order 481] is raising is: can storage obtain enough compensation in the market, especially in markets where it's hard for storage unless paired with something else (such as solar PV) to provide a capacity product?

"But it's opening up, setting the rules of the organised market so that they can make accommodations as needed for storage and also the clarity of permitting storage devices to charge at wholesale [prices]."

On the subject of clarity, while the FERC Order 841 saga and in particular the recent pushback continue, in Europe, in both the UK and mainland Europe, a more basic regulatory issue continues to play out. As we hear from the continental European Association for the Storage of Energy (EASE) in this special report, so-called 'double-charging' remains a huge, huge stumbling block for grid-connected energy storage (see p.38).

In the UK, too, a regulatory definition for energy storage has only just been proposed by the regulator, Ofgem. At present, energy storage is quite often still categorised as generation, Kirsti Massie, a UK-based lawyer with White & Case, says. Not having a dedicated definition or even a licence for energy storage, has "implications across a number of pieces."

"If you have a generation licence it means in the UK certainly, as a transmission system operator or distribution network operator, you're not also going to be able to own and operate storage facilities because they can't become part of the grid because the way their licensing is structured," Massie says.

"As a generator you're often looking to smooth out intermittency to renewables. That's fine but storage can do a lot more than that and it can provide grid services – it's not just an add-on to generation. Grid services are hugely important and become increasingly important as more renewables come on the wires," Massie says, while, as with mainland Europe, double-charging still exists.

"Also as a generator you will pay system charges when you're charging up your battery but you'll also pay when you're actually discharging the power from the battery. You're getting hit both times."

Grid service markets are not often enough structured in such a way to take advantage of the fast-responding, low carbon generation-enabling qualities of energy storage. As a lawyer, Massie says she looks closely at developments in the UK, Europe, the Middle East and Africa, but also works closely with colleagues in the US and Australia.

"What I've found very interesting is that the issues that we are talking about and that the industry and the regulator is trying to get their heads around in the UK are the same issues that you see in various markets in the US and in Australia. We've got a commonality of issues, in terms of questions people are trying to answer."

The customer will always come first

Deployed energy storage capacity around the world largely remains pumped hydro while lithium-ion is the current flavour of choice. Coming in all shapes and stackable up to hundreds of megawatts, the advantages of lithium-ion battery systems include how quickly they can be deployed and their rapidly falling cost. One of the challenges from a big picture perspective is going to be figuring out how much energy storage capacity is needed in front of the meter, providing services to the grid and capacity to utilities, and how much of it goes behind the meter, at customer sites.

These behind-the-meter sites are increasingly being aggregated to create energy trading opportunities and virtual power plants (VPPs). In much of the US, however, residential net metering for solar obviates much of the financial case for batteries in the home while in other territories, feed-in tariffs still reward customers well for energy delivered to the grid.

"It (net metering) effectively pays the homeowner the fully delivered cost of power. So I don't think you're going to get this notion of all these distributed residential resources getting together to sell power because they'd have to give up the benefits of net metering," Jennifer Key says, with some 40 US states still running net metering programmes.

So again, there will be some specific parts of the US adopting VPP programmes earlier than others: Energy-Storage.news reported on a 12.6MWh VPP in Utah from Sonnen and utility Rocky Mountain Power across 600 apartments as this edition went to press, for example. In other global markets however such as Japan, Australia, the UK and Europe including Germany, the cutting of feed-in tariff support is inspiring homeowners with solar to 'go battery storage' too.

A recent blackout in the UK which affected one million electricity customers was responded to by frequency response assets including 6MW of aggregated residential storage, acting as a VPP, from independent utility Social Energy. To be able to do this on a grand scale and as the norm, using both large and small ESS assets, will not only require more simplified and readily accessible revenue streams for grid services, it will also require coordination of effort and engagement with the end customer.

"Decentralisation, decarbonisation is the right thing to do, but we can't forget the consumer in all of this because the consumer is fundamental," says Faisal Hussein of UK industry body Flexi ORB (Flexible Energy Oversight Registration Body).

"In our focus on decentralisation and decarbonisation, we've got to be careful that we don't leave the consumer behind."

If the industry is ok, is that enough?

Despite some significant challenges, the adoption of energy storage as both an essential companion for renewables and as a flexibility resource for the grid in its own right appears healthy enough to suggest that in key markets adoption will only increase. Elsewhere, off grid, the economics are even better, and recent interest in microgrid companies active in emerging markets from major energy companies means that energy storage for energy access is also a reality.

At Solar Media and in particular through Energy-Storage.news, we'll be looking at some of these challenges in the coming months, as well as others we have barely mentioned, including the supply chain and end of life management (although you can read about the efforts of one company, Li-Cycle in Canada, to create an effective system for battery recycling on p.45). There's also the integration of data and fire safety, the choice of technologies, whether batteries, lithium batteries, or otherwise.

We're certainly encouraged to see so much proactive discussion of how many of these problems can be solved, and for many of our readers coming from a renewable energy background, a difficult challenge is nothing new. In regulation and many other areas however, "we've got away with a sticking plaster approach so far", Kirsti Massie of White & Case says, but the existing frameworks in the UK and many other regions still need to catch up to the progress – and promise – of energy storage technology.

"Trying to shove it in an existing framework, I think, limits the value [of energy storage]," Massie says. "You're not going to be able to take full advantage of the flexibility that storage can offer, if you're constraining it within a regulatory framework that dates way back before some of these technologies were even thought of."

As Massie says, there's been a huge amount of progress and it's certainly not a negative picture out there today for the energy storage industry. If we are to meet policy goals in reducing carbon emissions and transitioning to renewable energy, however, "energy storage inevitably is going to have to play a bigger role", Massie says.

"In order to play a bigger role, you need people who are willing to invest and to invest and develop at scale. One of the key things that then will arise, is, how are you going to finance this? If you're not able to really leverage off all of the benefits that storage can bring, the full flexibility of the storage offering, you're kind of limiting your revenue stream and that makes it more tricky and difficult to attract financing and I think will get in the way of the real, scale deployment of storage that is going to be key." ■

LA's big ambitions

By Janice Lin & Jack Chang, Strategen Consulting

Even in progressive California, Los Angeles stands out with its bold plans to decarbonise its power sector. The city's municipal utility, Los Angeles Department of Water and Power (LADWP), is the United States' largest publicly owned utility. LADWP is fully embracing energy storage as a critical tool for achieving the city's clean and affordable energy goals.

LADWP is already very familiar with the benefits of energy storage. It operates a 20MW lithium-ion battery storage system at its Beacon Solar Plant as well as a 1,500MW pumped hydro facility at Lake Castaic. In February 2019, LADWP announced it will not be replacing three gas-fired power plants scheduled to close by 2029. Instead, the utility will employ clean-energy alternatives such as solar and energy storage to make up for their 1,660MW of generation capacity. In July, LADWP proposed building the largest capacity utility-scale solar battery project in the country to date. The plan, submitted by developer 8minute Solar Energy, would build as much as 400MW of solar capacity and 300MW of energy storage at the historically low price of US$19.97 per MWh. As of early August, approval is pending at the LADWP board.

These moves are aligned with the city's Green New Deal, which lays out ambitious sustainability targets and devotes billions of dollars for new infrastructure. The plan calls for increasing cumulative energy storage to as much 4,000MW by 2050 – far larger than the current target for the entire state of California (1,500MW). Driving all that energy storage demand is the city's goal to supply 55% of its electricity needs with renewable energy within six years and 100% by 2045. Much work remains but given the leadership of the city and state, Los Angeles is well poised to succeed in achieving its clean energy goals with storage.

Year	Cumulative energy storage (MW)
2021	1,524
2025	1,750
2035	3,000
2050	4,000

LA's energy storage goals to 2050

Market and technology development of stationary battery storage systems

Economics | The business models and technologies underpinning the development of stationary energy storage markets are evolving rapidly. Dr. Kai-Philipp Kairies, Jan Figgener and David Haberschusz look at some of the key trends driving the sector forward

The international market for stationary battery storage systems (BSS) is growing rapidly. Within less than a decade, grid-connected BSS have evolved from a niche product to a mass market in which today international energy and automotive companies are competing for market shares. According to a recent study by BloombergNEF, almost 4GW of new battery storage systems went online in 2018 worldwide – and the market researchers expect this number to double by 2020 [1]. Accordingly, the International Renewable Energy Agency (IRENA) predicts that a total storage capacity of up to 420GWh will be installed by 2030 (see Figure 1).

Grid-connected storage systems today are used for a multitude of purposes, ranging from small-scale applications, such as residential home storage systems, to multi-megawatt batteries that provide balancing services and mitigate grid congestion problems on all voltage levels.

In this article, we will cover the three main market segments of stationary storage systems in Europe – private households, commercial buildings and storage for balancing services – and shed some light on the business models and profitability of these systems.

Credit: SPP

Battery systems sitting alongside solar projects, such as the UK's Clayhill, will become more common as storage plays an increasingly important role in grid balancing

Home storage systems

Over the last five years, more and more households have adopted battery storage in combination with photovoltaic systems. These so-called home storage systems (HSS) store excess solar energy during the day and make it available for self-consumption in the evening and at night. They provide a twofold benefit for the battery operator and the distribution grid: on the one hand, the operator of a HSS decreases the amount of electricity bought from the grid, thereby reducing his electricity bill. On the other hand, HSS can stabilise power grids with high amounts of renewable energy generation. By storing PV power during peak generation periods, local problems with voltage stability or thermal overloading of electric equipment can be mitigated. Several studies have shown that the use of HSS can reliably limit the maximum feed-in of PV installations to just 40% of their rated power without curtailing undue amounts of renewable energy [3]. This means that HSS can increase the maximum PV penetration of a given distribution grid by a factor of up to 2.5 without having to upgrade the electrical equipment. In some cases, HSS can also benefit from time-of-use schemes by offsetting higher tariffs at night and thus generate additional revenues.

The market for HSS has seen a massive growth in areas such as California, Australia, Italy and Germany. Japan could also emerge as a new, important market for HSS as rooftop PV installations become increasingly popular while electricity rates are comparably high. The German market for HSS is unique, and a research team of Aachen University, one of Europe's largest technical universities, has closely monitored its development from the very beginning. In the scope of a scientific monitoring programme, datasets of more than 23,000 individual HSS were collected that allow a deep insight into the mechanics of this emerging market. Some of the key findings of this ongoing evaluation are presented below.

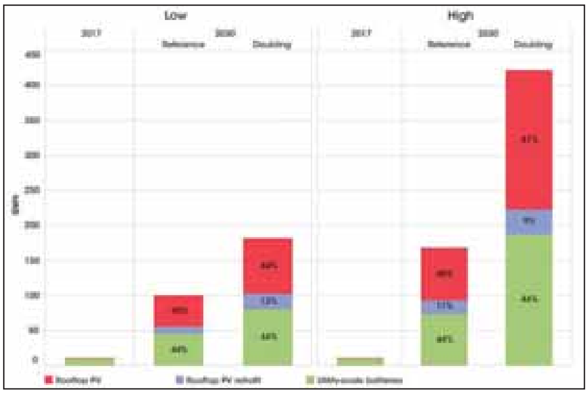

Figure 1. Development of stationary battery storage systems according to IRENA [2]

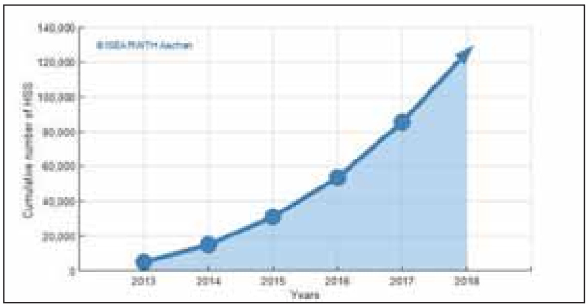

Figure 2. Development of HSS installations in Germany

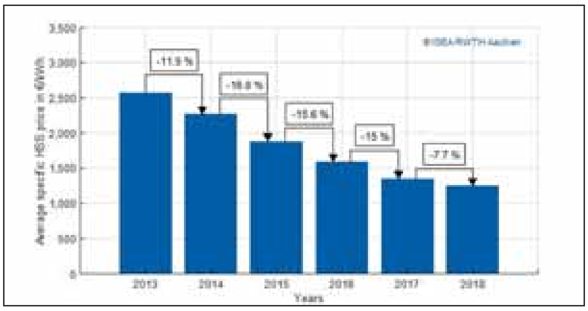

Figure 3. Development of retail prices (incl. VAT) for home storage systems in Germany

Since 2017, every second new residential PV installation in Germany has been accompanied with a battery pack. In some federal states, it is more than two out of three. In total, about 150,000 HSS with an estimated capacity of about 1GWh and a nominal power of 400MW are installed in Germany today (see Figure 2). These impressive growth rates also make HSS increasingly relevant to German utility companies and grid operators. Accordingly, a vast number of research projects focusing on the grid effects and the potential use of decentralised batteries in virtual power plants was initiated over the last years, making it one of the hottest topics in energy research.

Much has changed since the commercial success of HSS began in 2013. One major technical development was the battery of choice. While in the early days of the market, more than six out of 10 HSS were using traditional lead-acid batteries as their storage technology, lithium-ion batteries quickly gained market share. Since 2017, they account for more than 99% of all newly installed HSS. The reasons for this remarkable success of lithium-ion over lead-acid batteries are diverse: technically, lithium-ion batteries offer a maintenance-free operation, promise longer lifetimes and feature better roundtrip efficiencies. However, from a customer's point of view, two main advantages seem to outweigh all other aspects. Firstly, due to their very high energy densities, lithium-ion HSS are much more compact and can be mounted to walls, which allows a more efficient use of space and is sometimes perceived to be visually more appealing. The second reason is pricing. Between 2013 and 2018, the average retail price for HSS with lithium-ion batteries fell by more than 50%, whereas prices for lead-acid batteries decreased only slightly [4]. The plummeting costs of lithium-ion batteries not only bolstered their market share, but also helped to push the whole HSS market segment into the mainstream.

Interestingly, while system prices per kWh have been cut in half since the start of the scientific evaluation, the average system expenses of HSS remained virtually unchanged at roughly €10,000 (incl. VAT) over the entire period. The reason for this can be found in a constant increase in battery capacity since 2014. Simply put, customers seem to have invested every euro saved due to cheaper batteries into larger storage capacities. The increase in capacities of lithium-ion batteries from around 6kWh in 2015 to over 8kWh in 2018 are depicted in Figure 4.

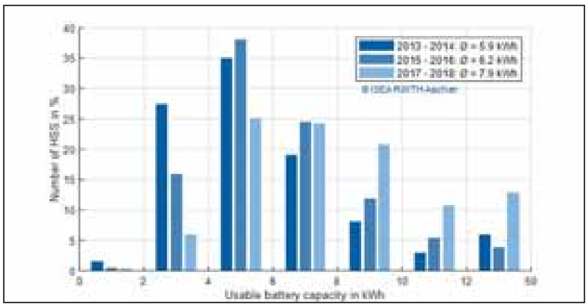

Figure 4. Development of the average usable battery capacities of German HSS

A recurring question is the reason for the ongoing HSS boom and one natural answer seems to be their economic benefit. By increasing self-sufficiency and thereby reducing the monthly electricity bills, the investment into a solar battery should pay off within a few years. However, while HSS are often promoted to be a financially attractive investment, the reality is more complex. With average investment costs exceeding €1,000/kWh and typical annual usages of fewer than 250 cycles, payback times for HSS today are in the range of 20 years for most households – a timespan that exceeds the expected lifetime of typical lithium-ion batteries by about one third. Even taking public financial incentives into account, most solar batteries today fall short of a break-even.

Whey, then, are consumers still so excited about it? To get a better understanding of the market mechanisms behind the HSS boom, participants in the scientific monitoring programme were asked a couple of yes-no questions regarding their purchase motivation (see Figure 5). More than 80% of the respondents in Germany stated that the main reasons for investing into a home storage system are to hedge against future increases in electricity prices and the desire to proactively participate in the transitions towards renewable energies ("Energiewende"). In addition, a "general interest" in the technology was a major purchase argument for more than 55% of the home storage operators. By contrast, only 20-25% stated that the wish to make a safe financial investment or securing against power outages was decisive for their purchase. The data suggests that the largest proportion of HSS operators today fall into the category of "innovators" or "early adopters". These population groups tend to be well educated, wealthy and interested in new technologies, paying less attention to the profitability of an investment and showing a high interest in the details of the technology. An additional factor for the rapid growth of the HSS market can be attributed to the sluggish PV market over the past years. A solar technician can double his sales by selling a battery in conjunction with solar panels, so many installers have pushed batteries to make up for the drop in solar PV orders. For many, storage has become essential for survival in this extremely regulation-driven market.

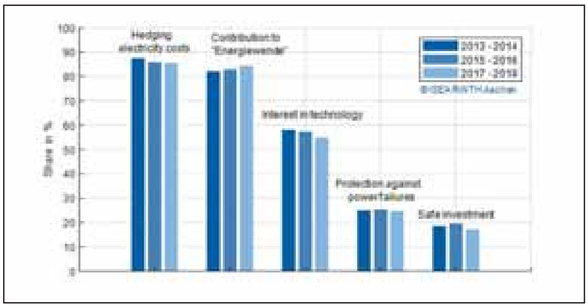

Figure 5. Purchase motivation of home storage systems in Germany.

Battery storage for commercial buildings

While HSS can be seen as a typical "emotional" B2C product, where profitability often is not a priority, business leaders need to make economically sensible decisions when investing into BSS. However, the diversity of possible applications and the complexity of the individual business models make it difficult to make general statements about the profitability of BSS in commercial and industrial environments. To allow a first understanding of the potentials and challenges of this

Figure 6. PV installation on a commercial building

market segment, two examples are briefly outlined in the following.

Increasing solar self-consumption The combination of PV and battery storage is also an option for commercial buildings with suitable roof surface areas. Depending on the system sizing and the individual load profile, up to 50% of the electricity consumption can be provided through decentralised clean generation. However, complete self-sufficiency from the grid is usually not feasible due to the low irradiation values in the autumn and winter months. In addition, the payback periods of these systems usually greatly exceed the expected service life of the battery storage systems. Nevertheless, many large international corporations are working intensively on this use-case as part of their efforts to increase the use of sustainable energies and reach their self-set CO2 reduction goals. Furthermore, large solar batteries can also be used as a means to mitigate blackouts or reduction in supply quality (so-called "brownouts"). Especially for manufacturing companies even a temporary drop in grid voltage can lead to considerable follow-up costs. In paper mills, for example, a brownout can lead to multi-day production stoppages, as the machines need to be cleaned after an unscheduled interruption. Compared to the potential financial damage of such an event, the investment in a battery storage system is often the more cost-effective option.

Reduction of peak loads Due to their extremely fast response times and good scalability, BSS are ideal for reducing peak electricity demand. This use case can be particularly interesting if the company's electricity price has a significant power component or if new loads are added that cannot be covered by the existing grid connection. As an example, Figure 7 shows the load profile of a small data centre located in the German state of North Rhine-Westphalia. The data centre is connected to the medium-voltage grid and has an annual peak load of 122kW and an annual electricity consumption of 581MWh. According to the grid operator's cost tables, annual savings of more than €1,000 can be achieved by reducing the company's peak load by 12kW (blue line in Figure 7). Using a holistic simulation of different energy storage systems it can be shown that a lithium-ion battery of only 8-12kWh would be sufficient to realise these savings, allowing an amortisation period of about six years. Because the battery is only used a few hours of the year, additional revenue streams, such as providing balancing power to the grid, can be tapped (so-called multi-use or value-stacking). By operating flexibly in different business models, BSS can optimise their revenue streams and further reduce their amortisation time.

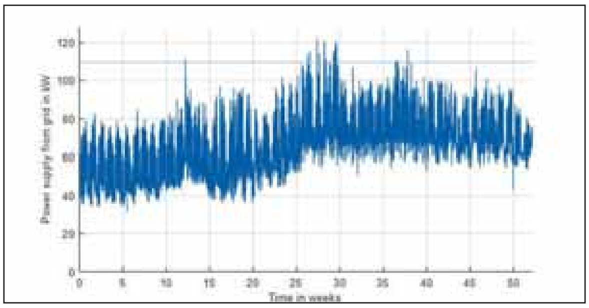

Figure 7. Load profile of a data centre in Germany. Annual savings of more than €1,000 can be realised if the peak demand is reduced by 12kW (blue line)

Battery storage for balancing services

For a stable operation of our power grids, the generation and consumption of electricity must be in balance at all times. Yet, this balance is regularly upset: failures of power plants and transmission lines or forecasting errors of renewable power generation can lead to a sudden over- or undersupply of electricity. In such cases, balancing services such as frequency control or reactive power management come into play to keep the grid frequency and voltage within a given range until the regular operation is restored. Traditionally, large generators such as coal-fired power plants performed these services. However, decreasing numbers of fossil-fueled power plants in our grids spark the demand for new suppliers. BSS are promising assets for providing balancing services due to their extremely fast response, good scalability and quick deployment time. Although often considered a new and upcoming application, utility-scale BSS for grid services are nothing new. In 1986, a 17MW lead-acid battery plant was installed in Steglitz, Germany, to supply frequency control to the then isolated (and notoriously unstable) electricity grid of West Berlin. What is new are the scales and timelines of such BSS projects. In 2017, Tesla built a 100MW/130 MWh containerised lithium-ion storage system in Australia within just three months. Compared to the long planning horizons of transmission grids, this is almost unimaginably fast.

The most important markets for utility-scale BSS in Europe today are Germany and the UK. In Germany, more than 450MW of large-scale BSS went online over the last five years. Most of these projects are in the range of 5-15MW with storage durations of about 1.5 hours and operate in the market for primary control power ("Primärregelleistung"). Primary control power is the fastest balancing service in the UCTE grid and similar to the (dynamic) firm frequency response in the UK. Together with a handful of other countries, Germany is responsible for supplying about 750MW of primary control power to the grid. The service is auctioned in daily tenders of 1MW increments at the energy exchange (EEX) in Leipzig. In order to participate, market players need to be able to ramp up to their nominal power in less than 30s and sustain a constant power output for

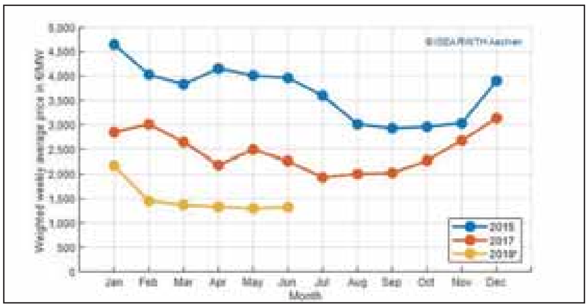

Figure 8. Development of prices for providing primary control power in Germany [5]

15 minutes, requirements easily met by modern lithium-ion batteries.

Still, BSS might have been just too successful too quickly. The entry of large numbers of BSS into the market for primary control power since 2013 turned the energy sector upside down and eventually diminished their own business case. The rapid increase in new market participants flooded the market with cheap biddings. Between 2013 and 2017, the number of weekly bids for supplying primary control power increased by 1,400%. At the same time, prices were cut in half, making the business case successively less attractive. In the first half of 2019, weekly volume-weighted prices fell to an all-time low of €1,300/MW per week. As other potential revenue sources for utility-scale BSS with short discharge times, such as providing black start capability or reactive power to the grid, are not established in the market yet, many new projects for this market segment of BSS have been shelved. One major obstacle to the development of new business cases for utility-scale BSS is regulation. Today, battery storage systems are considered electricity consumers when in charging mode, and generators when discharging, forcing them to pay some levies twice. While the government has promised to rectify this issue soon, many legal and operational questions remain open.

As an island grid, the UK's energy system has a higher demand for balancing services than other countries. While Germany is well connected to its neighbours, with roughly 40GW of cross-border trade capacity at 80GW peak demand, the energy exchange between the UK and its neighbours is limited. With higher shares of renewable power generation, new flexibility options are needed to compensate the lack of transport capacities. The system operator of the UK, National Grid, calculated that, in order to reach the UK's carbon reduction targets, more than 6GW of electricity storage are required until 2026 to support the grid integration of renewable energies [6]. But even today system stability can already become an issue: due to a sudden shutdown of a gas-fired power plant and a large wind park in Wales, lights went out for almost 1 million households in early August (see p.114). Increasing amounts of utility-scale BSS can prevent, or at least mitigate, the effects of such events by bridging the power gap until new generation units go online. Accordingly, the UK already introduced a new ultra-fast balancing service in 2016. The so-called Enhanced Frequency Response (EFR) requires service providers to ramp up to their nominal power in less than one second, the most demanding conditions for a balancing service, worldwide. The national grid operator accepted eight tenders totaling 201MW of capacity at a committed cost of £66 million over four years with batteries winning contracts hands down. National Grid expects to return an economic benefit of £244 million in avoided costs over the duration of the contracts [7].

In addition to providing balancing services, plummeting costs of lithium-ion batteries open up new use cases for stationary storage system. One particularly interesting market segment lies in BSS with a duration of about four hours. Combinations of such storage systems with renewable energies, especially PV, are increasingly used to replace gas-fired power plants to meet the peak demand. Another potential use case for multi-megawatt battery storage systems might be evaluated in Germany soon. In just a few years, massive BSSs with nominal powers of up to 500MW could be installed in Germany to support the transmission grids and enable the faster expansion of renewable energies while at the same time phasing out coal and nuclear power generation. Three of the four German transmission grid operators have submitted applications to the German grid regulator to test so-called grid boosters, battery storage systems with a total capacity of 1.3GW. These battery systems – shortly speaking – add an extra layer of security to the transmission grids and allow a higher utilisation of existing power lines. Thereby, transmission capacities can be increased by more than 30% in some cases. In the event of a failing substation, for instance, BSS can take over until the grid operator completes a redispatch. At the same time, however, the use of grid boosters presents grid operators with new challenges, as it requires a more complex network automation. In the event of a component failure, numerous switching operations must be coordinated in the shortest possible time.

Summary

Stationary BSSs are at the edge of profitability in many market segments today and will play a crucial role in enabling the next phase of the international transition towards renewable energies. The practical insights into the operation of grid-connected battery systems gained today will also help us to manage growing quantities of electric vehicles in our grids. We can be curious to see which innovative applications BSS will open up in the coming years. ■

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Authors

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Go big, go DC

Storage system architecture | New technologies and designs aimed at driving down the cost of energy storage facilities are currently the focus of intense industry R&D. Sara Verbruggen reports on DC coupling, an emerging system architecture that many believe will soon become the industry standard

As the costs of solar PV modules continue to reduce, and those of batteries follow a similar downward trajectory, solar-plus-storage is in growing demand among utilities and solar developers.

The US is leading the trend, where these types of clean energy power stations are starting to produce electricity competitively with gas peaking plants, especially when other revenue streams from grid services are factored in.

To further push down the levelised cost of energy (LCoE) of solar-plus-storage and maximise the amount of megawatt hours (MWh) of solar-generated electricity that can be fed into the grid, energy suppliers and developers are turning to direct current (DC) coupling these installations.

Compared with alternating current (AC) coupling, DC coupling the PV array and the battery storage system in front-of-meter installations, such as utility-scale plants, is a much newer, less standardised approach. This had led some US utilities to begin piloting these configurations to see how the technology performs. On the supply chain side, balance of plant (BoP) equipment manufacturers are delivering more standardised and simpler to use power electronics equipment for enabling DC-coupled plants.

DC- versus AC-coupled solar-plus-storage

In AC-coupled solar-plus-storage installations there are two inverters, one for the PV array and another for the battery energy storage system.

With this system configuration, both the battery and solar array can be discharged at maximum power and they can be dispatched independently or together, providing the operator with more flexibility in terms of how they operate and dispatch the asset. Located at the same site the solar array and energy storage facility can either share a single point of interconnection to the grid or have two separate interconnections.

Credit: Dynapower

A DC-coupled battery at Duke Energy's Mount Holly test site. Expectations are high that DC coupling will help drive down solar-plus-storage costs

In DC coupling, the co-located solar and energy storage assets share the same interconnection, are connected on the same DC bus and use the same inverter. They are dispatched together as a single facility. DC coupling reduces efficiency losses, which occur when electricity current is converted, such as from DC to AC (Figure 1).

According to Wood Mackenzie analyst Mitalee Gupta: "Hybrid approaches emerged in the past where you would see both PV and batteries connected to the grid via one multiport inverter, a configuration more common in behind-the-meter DC-coupled systems. But one of the disadvantages for the front-of-meter market has been the cost of multiport inverters."

The newer variation of DC architecture that has emerged for front-of-meter solar-storage, which Gupta is referring to, is a DC-DC converter. This piece of hardware is tied to the batteries and connects to the PV inverter along with the PV array, allowing for a single interconnection only.

Reduced capex

Since interconnection can make up anywhere between one fifth to over a third of BoP costs, DC coupling can help reduce these costs. Co-locating different assets, be it solar and storage, solar and wind or solar, wind and storage, will always reduce BoP costs, compared with a standalone installa-

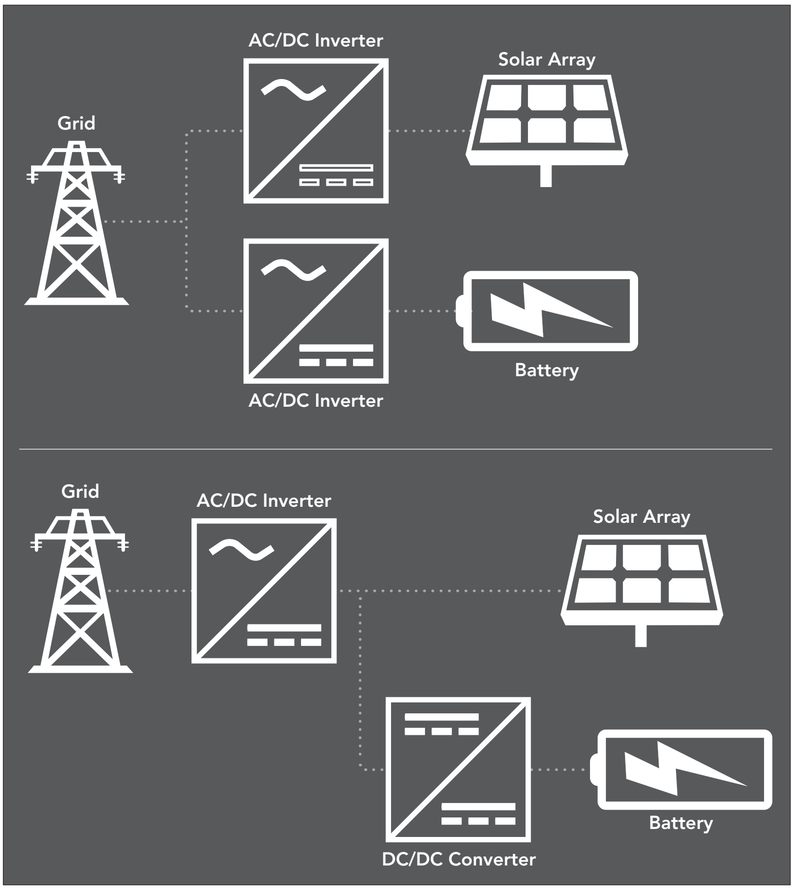


Figure 1. Co-located solar and storage systems, in AC-coupled (left) and DC-coupled (right) configurations

tion of a solar or wind plant, simply through sharing costs associated with land acquisition or leasing, labour, project management and permitting.

The US National Renewable Energy Laboratory (NREL) estimates that by 2020, BoP costs for co-located DC-coupled solar-plus-storage will be 40% lower and those for AC-coupled solar-plus-storage will be 30% lower.

Business case for clipping recapture

According to analysts IHS Markit, return to stronger global solar growth in 2019 is occurring, driven by declining PV module prices, which have fallen by 32% on average in the past two years, while average PV inverter prices have also been falling, by 18% over the same period. As the cost of modules continue to come down, DC coupling becomes increasingly advantageous when designing a solar-plus-storage plant, in order to outsize the plant's solar capacity.

Eos Energy Storage business development manager Philippe Bouchard says: "As well as capturing more cheap solar energy for sending to the grid, you also have a dispatchable power plant and are able to maximise its output too. Power is being fed into the grid in the morning, in the day and in the evening."

One company that has done modelling around clipping recapture is US power electronics company Dynapower. Through its activity in the energy storage business during the past 10 years, the company saw the advantage of DC coupling, before developing conversion hardware to enable these types of installations. Dynapower launched the first DC-DC converter aimed at the utility-scale solar-plus-storage market in 2018.

In AC-coupled solar-plus-storage configurations optimal PV inverter loading ratios are around 1.30 for the PV array (DC rating) to 1.0 for the inverter (AC rating). Using the example of a 100MW AC inverter connected to a 130MW DC solar array, the plant's output is 100MW, resulting in many megawatt hours of clipped energy annually.

Connecting energy storage to the PV array by DC coupling allows for the PV-to-inverter ratio to be significantly increased, and output otherwise clipped and lost in the more conventional AC-coupling approach is used to charge the battery.

According to financial and technical analysis undertaken by Dynapower for DC-coupled solar-storage under the Solar Massachusetts Renewable Target (SMART) programme, an owner of a solar-plus-storage system comprising a 3MW PV array, a 2MW (AC) PV inverter, which is DC coupled to a 1MW/2MWh energy storage system, will be able to capture 265,388kWh of clipped solar energy annually, resulting in US$1.5 million of additional annual revenue, compared with an AC-coupled solar-storage system. The return on investment is estimated to be 5.6 years.

Pilots

Dynapower has worked on several pilots with utilities that are first movers in doing DC-coupled solar-plus-storage installations. These include NextEra and Duke Energy, which have deployed the company's DC-DC converter technology.

In the Citrus project in DeSoto in Florida, NextEra subsidiary Florida Power & Light has installed a 4MW/16MWh lithium-ion battery system DC-connected to a PV array, which has been in operation since late 2018. The utility is comparing the benefits of the Citrus facility against a 10MW/40MWh AC coupled solar-storage plant, Babcock Ranch, in Charlotte County, also in Florida.

In these pilots NextEra is interested in how storage paired with a PV facility can capture a portion of the solar megawatt-hours that are clipped during peak solar output hours for delivery to customers later in the day.

The utility sees the advantage of DC-coupled solar-plus-storage compared with AC coupling as an ability to capture a greater amount of clipped solar energy, combined with a higher round-trip efficiency (charging to discharging). However, it acknowledges that AC coupling approaches are better known and understood. As both projects continue, NextEra says it will adapt its assumptions.

Dynapower has also supplied its DC-DC converters to pilots undertaken by Duke Energy. They include an installation at Duke's premises in Mount Holly, North Carolina, as part of a microgrid, which includes a 150kW solar array coupled to a 240kW/122kWh Total (Saft) battery system with Dynapower's 250kW DC-DC converter.

This August, Duke Energy will commission another DC-coupled solar-storage installation using alternative battery chemistry at its McAlpine facility, also in North Carolina. Eos Energy Storage has supplied a 30kW/120kWh energy storage system, based on its aqueous, zinc battery technology, which is integrated with Dynapower's DC-DC converter technology.

Dynapower marketing manager Richard Morin says: "These projects are exciting because, until now, what's slowed the floodgates for DC-coupled solar-plus-storage is that it presents a new technological approach to doing these types of projects, but with these pilots utilities are putting the benefits of DC-coupled architecture to the test, ahead of wider adoption."

To expedite the rollout of DC-coupled solar- plus-storage projects in the future, Dynapower is partnering with large, global manufacturers of central inverters. "We are kind of behind the scenes with our converter. We have designed it to be compatible with different PV inverter makes and pave the way for more plug-and-play type offerings, so we are in the process now of partnering with global suppliers of utility-scale PV inverters, including SMA," says Morin.

One often-cited disadvantage of doing DC-coupled projects is that the batteries have to be installed in a distributed way throughout the solar array, compared with an AC coupled installation where one central container of batteries is installed.

While it is technically possible to do a DC-coupled central battery storage system, it would entail a high number of long cable runs, making it more practical to co-locate the batteries with the central inverters distributed throughout the installation.

Gupta says: "If a site is space constrained, it may be better to do AC coupled. With DC coupling, blocks of energy storage are

DC microgrids

Growth in solar and other distributed generation as well as energy storage has helped fuel demand for microgrids, which can offer buildings and communities power resiliency.

According to Eaton's distributed energy segment leader EMEA, Louis Shaffer, by adding a smart operating system over the top of integrated distributed generation and loads, to create a microgrid, minimises overall peak demand, so the main grid becomes a source of back-up only.

Losses can be significantly reduced in DC microgrids, compared with AC. Clean distributed generation sources, including solar, batteries and also wind turbines, generate DC power, while loads, such as certain types of machinery, appliances, LED lighting and computing devices, run off DC power. The growing availability of critical components, like DC-DC converters, is simplifying design and development of DC microgrids.

Shaffer sees decarbonisation of cars and transport as a key driver for DC microgrids. Since electric car chargers run on DC power, EV charging could become a significant load for a building complex or campus that dedicates a percentage of its car parking area to charging. "So, the rationale increases then for designing a microgrid based on DC architecture," he says.

Dynapower's marketing director Richard Morin says the company is seeing growing interest for its DC-DC converters for different types of microgrid applications. "DC coupling loads and generation eliminate efficiency losses. We are having early stage conversations with companies in various industries, from manufacturing to mining."

distributed over the site and are connected to blocks of storage."

Other perceived disadvantages of DC coupling, compared with AC-coupling, include increased connection costs. Operations and maintenance costs could also be impacted, if technicians spend time getting to and checking or working on various battery containers spread over a solar field.

However, Morin says: "We have found that in speaking with our customers they prefer containerised distributed batteries for safety and risk mitigation. By distributing the batteries, if there was a thermal event, it would be contained to the singular battery container, reducing the scale of the event and loss of battery assets."

He adds: "Additionally, the types of large-scale solar installations that we are discussing typically do not require a lot of maintenance. The economic advantages of the DC-coupled approach, such as improved roundtrip efficiency, reduced installation cost and clipping recapture capability, far outweigh any additional costs for maintaining multiple battery structures."

Demand drivers for DC coupling

According to Fluence Energy's managing director Daniel Wishnick, the US is the only market where DC-coupled solar-storage is in demand at present. "These types of installations are tax-advantageous," he says, referring to the federal investment tax credit (ITC).

Gupta says that even with the ITC stepdown in 2021, DC coupling demand will continue as the industry becomes more comfortable with these types of projects and look to optimise revenues from clipping recapture and other streams.

"The number of integrators and working on DC-coupled projects is growing, including Fluence, GE and Greensmith, while more vendors are launching DC-DC converters and DC-integrated solar-storage solutions in the past 18 months. That said, at this stage the market has not achieved the same level of standardised, or 'plug-and-play' systems that AC-coupled projects benefit from," Gupta says.

Regarding integration, Bouchard points out that the real development work being done with these first projects is establishing the code and control interface to allow a system of components to interoperate seamlessly.

"In a typical DC-coupled solar-plus-storage project, you have the AC inverter, DC-DC converter, energy management system (EMS), battery management system (BMS) and DC solar array operating together to deliver maximum, dispatchable energy when called upon.

In most cases, all these components, including Eos' own BMS, use the same communication platform and what is known as SunSpec communication protocols, which have been developed by an alliance of solar and storage distributed energy industry companies, including SMA, NexTracker, Engie, Fronius and NEC participants, to support system interoperability.

While there is ongoing development work required in the EMS space to optimise dispatch according to contract or market requirements, Bouchard says that getting these systems to 'talk' to each other is not difficult.

"Once you've done it the first time, you can leverage the interface development and register mapping to replicate and scale for much larger projects," he says.

According to Wishnick, specifics of individual projects are influencing decisions on whether to DC- couple or not. "Site layout, interconnection costs and considerations can all have an impact on whether DC coupling or AC coupling is the best approach to take," he says.

Fluence is working with several customers, mainly developers of front-of-meter, ground-mounted solar-plus-storage projects, on DC-coupled designs. Most clients of Fluence are at the stage where this is their first DC-coupled solar storage project, indicating the market is still at an early phase.

Bouchard says: "As the US is by far the biggest market for solar-storage, naturally it is where DC coupling is happening first." In five years' time, he thinks it will be more widely deployed in US and also in other markets.

"We are seeing interest in India, Australia and especially Middle East, where you need a large solar-storage plant able to cover the evening load. In domestic terms interest is growing in south-west US and also California, as well as North Carolina, which is one of the fastest growing solar states in the US."

Bouchard says the company is supplying a DC-coupled solar-storage project in a market outside the US, though won't provide further details at this stage.

Morin says Dynapower is seeing global interest for its DC-DC converter for DC coupling solar and storage, noting Australia in particular, where electricity market changes are facilitating demand for DC-coupled solar-storage plants.

He is bullish about the prospects for DC coupling. "In the next five years it will be mainstream. If you look at the market research up to 2025, that is the trend. ■

SolarEdge readies for rise in demand for DC coupling in residential solar-plus-storage

Another market where DC coupling is seeing more demand is in the residential PV market, where adding batteries increases self-consumption of solar-generated electricity.

According to SolarEdge founder Lior Handelsman, DC coupling behind-the-meter solar and batteries for residential markets results in more energy production and increased return on investment, because there is only the one conversion to AC after energy is discharged from the battery. AC coupling requires three conversions. "The reduced number means increased efficiency and energy loss is minimised," he says.

Depending on upfront costs, AC coupling can make more sense when retrofitting an existing PV system to include energy storage. But, Handelsman says: "DC coupling is becoming increasingly popular as more new PV systems are initially being installed with a battery. This is due to decreasing PV and battery costs, increasing electricity prices and evolving incentive structures."


Credit: SolarEdge

DC coupling residential solar and batteries results in more energy production and increased return on investment, according to SolarEdge

DC coupling also provides a number of other benefits. "A DC-coupled system requires only one inverter, which means simpler installation and reduced costs. Additionally, one inverter to manage the system means functionality benefits, such as simpler synchronisation and coordination of advanced features," he adds.

In addition, a DC-coupled solar and battery installation allows the system owner to use PV power above the inverter rating and the inverter does not limit power, in other words act as a bottleneck for the power flow due to energy conversion.

Initiatives for California to overcome its challenges in the sun

Technology | California's success in embracing renewable energy technologies, particularly solar, has brought with it challenges around reliability of supply to consumers. Janice Lin and Jack Chang of Strategen explore how the Golden State is pioneering the deployment of energy storage as it pursues its goal of complete energy decarbonisation by 2045

California is embracing energy storage as a reliability solution for an electrical grid that's adopting more renewable, intermittent generation. Public agencies such as the Los Angeles Department of Water and Power have set ambitious energy storage targets while companies across the state are developing cutting-edge storage technologies such as zinc-air batteries and renewable hydrogen. The goal is to ensure a dependable energy supply for the state as it races toward its target of 100% carbon-free energy by 2045.

For more than two decades, California has overcome a series of unforeseen challenges that have threatened to derail the state's transformation to clean, reliable energy. Whether it was cheap natural gas challenging the economics of renewables or California's push to implement the country's toughest auto emissions standards, state policymakers have untangled regulatory and economic clean energy knots years before other states or countries were even aware of them. In doing so, California reduced carbon dioxide emissions by 13% from 2004 to 2016 while its economy grew by 63%.

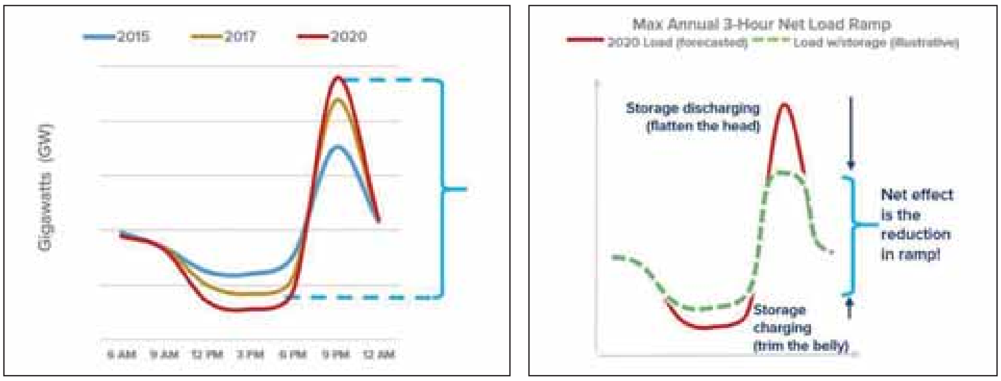
With the ramp-up of renewable energy generation, one of the trickiest challenges bedevilling state policymakers has been how to supply reliable energy to consumers despite the intermittent nature of solar, wind and other forms of renewable generation.

The California Independent System Operator, CAISO, christened this pattern the "the Duck Curve" to describe the net electricity demand they must serve after netting out daily solar and wind energy generation. The resulting net load has a regularly recurring daily dip and rise that looks like a duck. The addition of 20,000 megawatts of new renewable generation over the past nine years in the state has exacerbated that curve by steepening its slope over the course of the day as ever more solar energy floods into the market and then retreats.

Credit: Doosan GridTech.

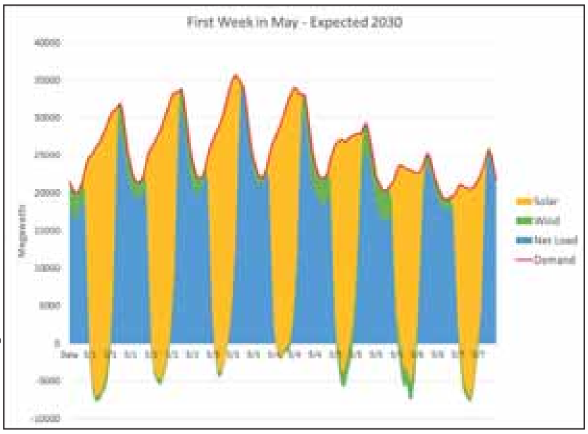
A planned 20MW battery energy storage system project for LA Department of Water and Power with Doosan GridTech

Visually, instead of the smooth, almost lazy "U" of diminishing and rising demand, the state now rides a daily roller coaster as millions of solar cells begin to generate power in the morning and then taper off production in the late afternoon – just as households turn on their TVs, washing machines and other appliances.

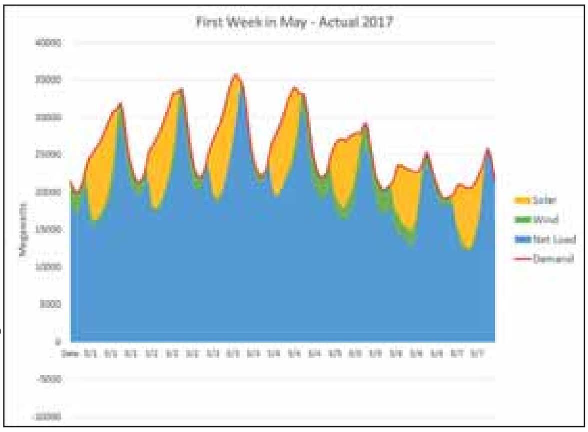


Source: Strategen

Modelling of daily net energy demand in California sees what CAISO christened the 'duck curve' become even more steep.



Source: Strategen



Source: Strategen

The Duck Curve over the course of a week in May 2017 (actual) and May 2030 (predicted) shows 'icicles of opportunity' on the grid.

Viewed on a weekly or monthly scale, the dramatic peaks and valleys of this peaking power profile appear something like multiple stalagmites rising from a cavern floor.

At the leading edge – of a complex energy problem

The addition of thousands of megawatts of solar energy has not only made the grid harder to manage, it has increased reliability on expensive, inefficient and polluting natural gas peaker plants to meet the ramp, which has hampered greenhouse gas reduction efforts.

So California once again finds itself at the leading edge of a complex energy problem, and its success or failure is likely to impact the renewable energy efforts of other states and regions around the world. That transition to a smoother energy profile requires storage because of its core ability to take energy from one period and dispatch it when needed in another period, freeing the grid from the constraints of renewables ramping up or down.

Leaders in both the state's public and private sectors have recognised that promise and have already created promising new storage technologies as well as a successful regulatory framework for enabling energy storage in all its diverse forms. Storage is transforming California's power sector while helping the state achieve its ambitious clean energy policy goals.

We at Strategen present here a shortlist of public and private energy storage initiatives in California that we believe have a good shot at bringing more reliability to the grid. Taken as a whole, efforts of both state agencies and companies are working with lots of creativity and daring to make widespread energy storage a reality:

Public initiatives

In 2018, Sacramento lawmakers went all-in on clean energy by passing Senate Bill 100, which requires 100% of the state's energy come from carbon-free sources by the end of 2045. That legislation has spurred cities across the state to incorporate storage in their energy plans, the most notable example coming from the Los Angeles Department of Water and Power's Green New Deal. L.A.'s ambitious initiative calls for increasing cumulative energy storage by 18% to as much as 1,524MW. It also identifies and prioritises solar and microgrid backup power projects at municipal facilities, streamlines permitting and interconnection processes for energy storage projects and launches pilot technology for dispatchable and customer-side storage.

Additionally, the state has launched a variety of incentive and pilot projects supporting energy storage.

SGIP

By the end of 2017, the California Public Utilities Commission's Self-Generation Incentive Program had funded 1,768 projects representing over 568MW of rebated capacity and supporting technologies such as advanced energy storage and fuel cells. Known as SGIP and introduced to primarily support solar generation equipment purchases, the programme paid more than US$845 million in incentives for completed projects.

EPIC

The California Energy Commission has already spent more than US$5 million and earmarked an additional US$30 million to support commercialisation of the next generation of energy storage technologies. Focusing on diverse battery chemistries, innovative energy management software, as well as thermal and mechanical storage technologies, the CEC aims to deploy storage that will meet a variety of use cases. Additionally, this past April, the commission awarded US$11 million to four energy storage technology research projects in its latest round of its BRIDGE, or Bringing Rapid Innovation Development to Green Energy, project. The commission funding supported an electric vehicle charging and energy storage programme from Natron Energy, a zinc battery storage project from Eos Energy Storage, a large-scale sulphur thermal battery demonstration project from Element 16 Technologies and a redox flow battery from UniEnergy Technologies.

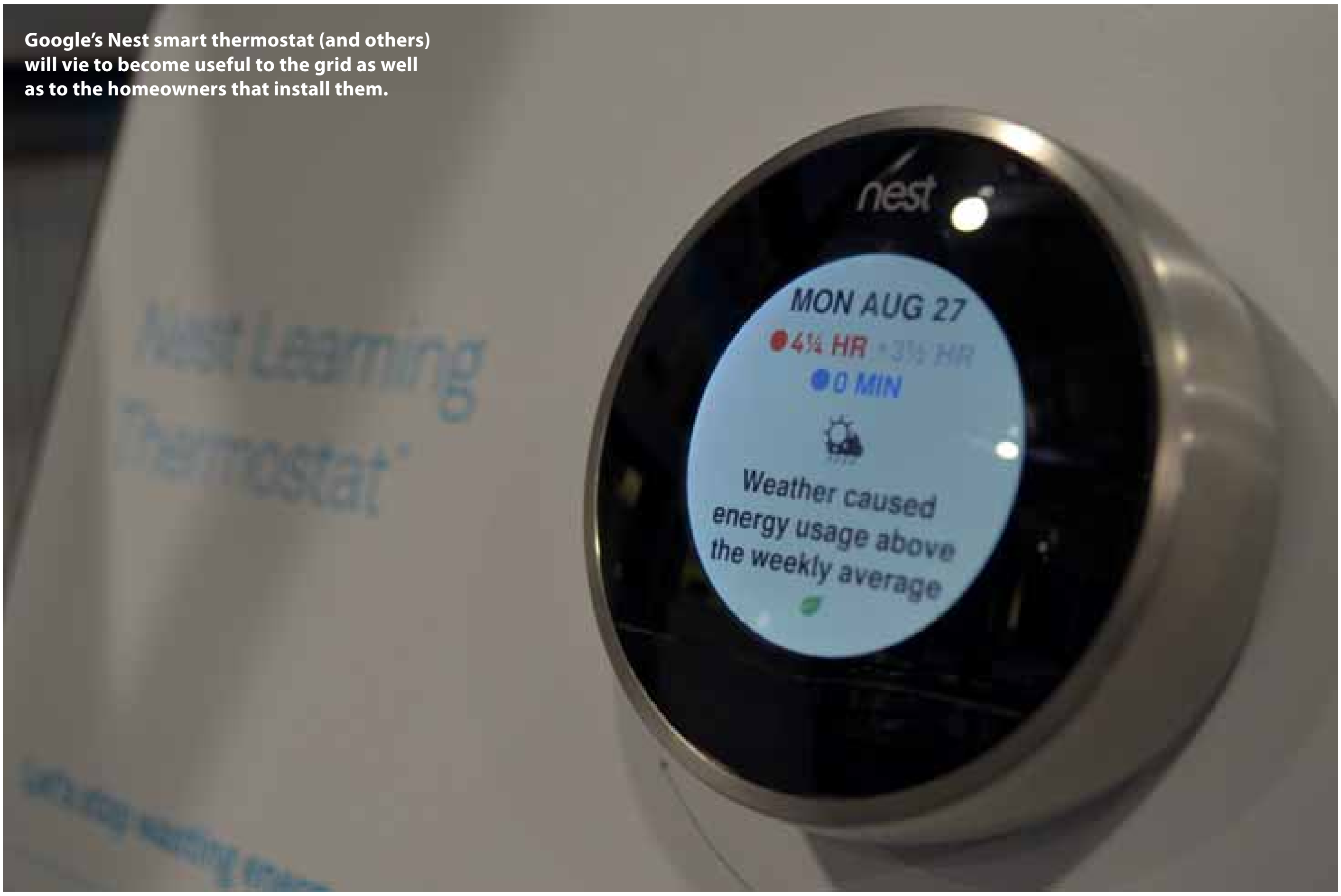
Private sector

Companies across California are tackling the storage challenge with the same type of scrappy start-up spirit that has reshaped the technology sector, and by extension, the world. The research and development action is happening at more established companies as well such as the Malta molten salt energy storage project launched at Google X, the tech giant's "Moonshot factory." Paired with forward-thinking policy coming out of Sacramento, the conditions are right for real storage breakthroughs.

Hydrogen

Hydrogen fuel cells are already powering thousands of buses and cars all over California, so much so that the technology is often linked principally to transportation. That's changing, however, as hydrogen is increasingly considered a potential long-duration, multi-day and multi-energy storage solution that can help flatten daily load. Companies are experimenting with new ways to produce hydrogen such as through the thermal conversion of garbage. Another big opportunity is to convert water to hydrogen gas and oxygen through electrolysis by harnessing solar and wind energy.

As prices for solar and wind continue to plummet, this cheap, abundant and clean electricity could produce climate neutral (non-GHG) hydrogen gas at scales large enough to eventually displace natural gas in some cases and



Google's Nest smart thermostat (and others) will vie to become useful to the grid as well as to the homeowners that install them.

Credit: Raysonho @Open Grid Scheduler/Grid Engine

even serve as a peaker resource. Renewable hydrogen could also come from Mitsubishi-manufactured turbines that run on a blend of gas and hydrogen, with the goal of running on 100% hydrogen within a few years. Such technology used at scale could repurpose for renewable hydrogen existing infrastructure such as gas pipelines and interconnections.

If the falling price trajectory of solar and wind energy is any indication, renewable hydrogen has the potential to become economically competitive with natural gas-derived hydrogen.

That means renewable hydrogen could displace gas use in industrial, electric generation, agriculture, long-haul transportation fuels and other applications. To push the hydrogen ball along, the state's Public Utilities Commission is considering a new docket that will analyse the feasibility of hydrogen injection in the natural gas pipeline and further define renewable hydrogen and its potential use as a storage as well as a natural gas substitute. The California Fuel Cell Partnership, a public-private group, argues that the state can leverage its 60-plus hydrogen fuel stations in operation or in development to help transform the fuel source as a high volume and seasonal storage medium. The state already requires that at least a third of the hydrogen sold at California stations be renewable. Building out that infrastructure at the needed scale, however, is seen as a potential challenge to hydrogen playing a viable role in any state-wide storage solution.

Long-duration storage

More renewable energy coming online will mean a growing need for long-duration storage that can even out the intermittency of solar and wind generation and bring reliability to a renewables-dominated grid. For grid operators, long-duration storage offers more flexibility in integrating wind and solar energy generated during different times of the day. That's especially important as gas-fired generation makes up a smaller portion of state-wide generation and capacity.

Zinc-air batteries have received attention as a long-duration storage alternative with the high-profile growth of El Segundo-based NantEnergy and its leadership under chairman Patrick Soon-Shiong, the billionaire owner of the Los Angeles Times. NantEnergy touts rechargeable zinc-air battery storage systems as cheaper than lithium-ion systems – about US$100 per kilowatt hour versus as much as US$500 per kilowatt hour for lithium-ion batteries. NantEnergy is already installing its battery systems in dozens of rural communities in Africa and Latin America as a proof of concept. The company has already raised more than US$200 million in funding.

The systems are often installed along with solar panel-powered microgrids run by advanced monitoring systems that help users analyse and adjust generation and load profiles in real time to better meet demand. The batteries use solar-generated electricity to separate zinc oxide into zinc and oxygen, with the zinc later combining with air when needed to produce energy. For zinc-air boosters, the best argument in their favour is that companies are already producing the units, the technology has been deployed around the world and it has shown itself to be a viable long-duration storage option.

Google X spinoff Malta Inc is exploring another long-duration storage pathway with its pioneering use of heat-trapping molten salt. The Malta process uses renewable electricity to power heat pumps that store heat in molten salt and cold in chilled liquid. When needed, a heat engine converts the temperature difference between the stored heat and cold back into electricity. The company says the technology can store energy for more than six hours and be charged thousands of time before its performance degrades. The simplicity of its materials – salt, steel, anti-freeze and air – gives the system an estimated 20-year product lifetime. Malta CEO Ramya Swaminathan and principal engineer Raj Apte are scheduled to deliver keynote addresses at ESNA on the future of long-duration energy storage.

Other forms of long-duration storage such as pumped hydro and compressed air require millions of dollars in infrastructure investment to operationalise, but that hasn't stopped California utilities from jumping in. Pacific Gas & Electric (PG&E), the state's biggest utility, is studying building a compressed-air storage facility in the agricultural San Joaquin Valley that would use energy during low demand periods to inject air into sand deposits or other porous rock formations. That air is then tapped to spin turbines and generate electricity when demand is highest.

Further south, the Los Angeles Department of Water and Power is already operating a pumped hydro system in the Los Padres National Forest above the L.A. basin that pumps water from Castaic Lake 7.5 miles uphill to Pyramid Lake during low demand times. When the electricity is needed, the system releases the water back into Castaic Lake where turbines await. The department is looking at implementing a similar storage system at the Hoover Dam.

Electric vehicles

With more auto manufacturers shifting to the electric vehicle market, successfully integrating all those Teslas, Bolts and Leafs into a dispatchable grid promises enormous benefits. As usual, California is leading the way, having already set a goal of putting 5 million zero-emission vehicles on the road by 2030 and installing 250,000 electric vehicle charging stations by 2025. The state's utilities have also been mandated to develop targeted EV plans establishing clear guidelines for charging by residential, commercial and industrial vehicles. As a result, the state's three main investor-owned utilities – Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric – have taken the lead nationwide in developing rate structures specifically to help electric vehicles charge when electricity is cheapest as well as to help pay for electrical upgrades at residential homes installing electric vehicle charging infrastructure.

Beyond charging, state planners are studying electric vehicles as load-management and energy storage resources especially as the state's EV fleet balloons. For example, smartly charging EVs system-wide during low energy-use periods alone could save the state US$1.45 billion to US$1.75 billion in stationary storage investments that would otherwise be needed to meet California's clean energy goals. The next step will be to encourage V2G, or Vehicle-to-Grid, policies and infrastructure that can help EVs send power back into the grid. System-wide V2G balancing capabilities would help the state avoid an estimated US$12.8 billion to US$15.4 billion in stationary storage investments.

San Diego-based Nuuve is already selling its patented V2G bidirectional AC and DC charging stations that ensure vehicles have enough charge to complete trips and also let them sell energy back to the grid if the price is right. Nuuve is collaborating with auto giant Honda to demonstrate the viability of such vehicle grid integration.

Household appliances

Taken individually, a water heater or a home thermostat doesn't make a big impact on total energy load. Together, however, millions of residential devices switching on or off in unison could be a real game changer. That's the idea behind moves both in the public and private sectors across California to get thermostats, heaters and other appliances into the storage and demand response game.

For example, California lawmakers are trying to transform millions of electric water heaters across the state into both mini-energy storage devices and replacements for natural gas-generated heat. Last year, the state Legislature passed State Bill 1477, which dedicated US$200 million over four years to help advance low-carbon space and water heating technologies. The big-picture goal is to decarbonise residences across the state by weaning them off natural gas and have them use electric appliances instead. Electric water and space heaters tapping an increasingly clean grid are seen as the linchpin to creating carbon-free households. On top of that, heat pump technology, when fitted with software that matches heating times with dips in energy prices, also make for excellent energy storage devices that can store hot water for later use.

In July of this year, Google-owned Nest announced it was pairing up with Leap, a San Francisco-based firm that runs a universal distributed energy exchange. Nest's smart thermostats will deploy energy to meet demand response capacity on Leap's exchange. Already, some 2,500 thermostats across the state are turning on and off in response to energy price signals sent from the Leap exchange. Multiply those thermostats' numbers many times over and those stalagmites of energy demand will really start shrinking.

Forward movement with clean energy

With these initiatives, California is tackling the challenges of building a more integrated, reliable electrical grid that makes full use of renewable generation and energy storage. Public agencies are creating the incentives and regulatory framework that can inspire private companies to invest in and develop the latest solutions to long-duration storage, demand management and other pieces of the reliability puzzle.

Many of these programmes and technologies will be on display at Energy Storage North America Conference & Expo (ESNA) in San Diego on November 5 to 7, 2019. In its 7th year, the event is celebrating innovation in energy storage alongside government leaders of California and Germany, two of the world's most clean energy-forward places, as it hosts the California-Germany Bilateral Energy Conference. ■

Authors

Janice Lin is the founder and managing partner of Strategen Consulting, where she brings more than two decades of experience in clean energy strategy, market development, and corporate strategy.

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Energy Innovation –

What to see at SPI, ESI, and North America Smart Energy Week

Solar Power International (SPI), Energy Storage International (ESI), and North America Smart Energy Week, powered by the leading solar organizations the Solar Energy Industries Association (SEIA) and the Smart Electric Power Alliance (SEPA), is the largest gathering of solar, smart energy, energy storage, and hydrogen+fuel cells professionals in North America. The event brings together 19,000 energy professionals and features over 700 exhibiting companies. SPI, ESI, and North America Smart Energy Week takes place September 23-26, 2019 in Salt Lake City, Utah, USA.

Solar Power International (SPI)

SPI is the largest solar event in North America. Attendees from over 120 countries will make Salt Lake City their home for four days to experience the largest and fastest growing solar trade show in North America.

SPI Education sessions include:

- Crowdsourcing energy: Community choice aggregation opportunities
- Utility scale solar plants of the future: Integrating energy storage, solar trackers, and software
- Solar cell recycling

Energy Storage International (ESI)

Energy Storage International is the largest energy storage event in North America. This year, ESI goes beyond solar+storage. As storage costs decline, viable energy storage solutions are emerging for utility-scale and distributed wind projects, enhancing their value.

Education sessions include:

- Solar plus storage plus load flexibility
- Integrating solar, storage, and electric vehicles
- The promise of solar and storage solutions for utilities

Hydrogen + Fuel Cells International

This is the largest gathering of hydrogen and fuel cells professionals in North America. Attendees can see how it all ties together, while hydrogen & fuel cell exhibitors can profit by demonstrating the versatility of hydrogen here in Salt Lake City.

Education sessions include:

- Scaling-up – future-proof reliable hydrogen fueling stations with high capacities
- Global hydrogen growth – the expanding hydrogen economy
- Scalable hydrogen fueling infrastructure

The Technical Symposium

The Technical Symposium offers professionals from the academic, R&D, technical and scientific disciplines in photovoltaics, energy storage and smart energy learning opportunities with new technology.

Education sessions include:

- Comparative performance of anti-reflection coatings under real-world conditions
- Enabling dispatchable renewable PV+S plants using MESA-ESS
- Advanced perspectives on technical diligence of solar+storage projects

Smart Energy Marketplace + Microgrid

The marketplace will include the entire solar, energy storage, hydrogen+fuel cells, EV infrastructure, wind, EV infrastructure and smart energy microgrid landscape. The marketplace features a fully-functioning "live" microgrid, power conversion equipment, energy management systems, building and home smart energy products, electric vehicle charging stations, energy storage systems, and solar energy products.

Education sessions include:

- Biggest isn't always better: Smart energy systems and micro-grids play in the dominant North American wind market
- Implementation considerations and financing for clean energy microgrids
- Distribution system infrastructure and planning to support optimized charging of vehicles

SPI, ESI, and North America Smart Energy Week takes place September 23-26, 2019 in Salt Lake City, Utah, USA. Visit **smartenergyweek.com to learn more.**

The Clean Energy Package is here – now what?

EU policy | The EU's clean energy policy framework for the first time recognises energy storage as a key part of the future energy system. It is far from perfect, but lays the foundation for storage to become an integral part of efforts to decarbonise the energy system, writes Brittney Elzarei

Only 10 years ago, the value of energy storage for the energy system was not at all recognised by European Union policymakers. In the Third Energy Package, the 2009 package of EU energy legislation, there was no mention of energy storage. In an energy system and regulatory framework built around the traditional assets of generation, transmission/distribution and consumption, energy storage was seen as a rather unimportant niche technology.

Just as the energy storage market has grown in leaps and bounds, the thinking of policymakers across the EU has evolved since then. The European Commission now recognises that "Energy storage has a key role to play in the transition towards a carbon-neutral economy, and it addresses several of the central principles in the Clean Energy for All Europeans package" [1].

This package of legislative and non-legislative proposals, commonly referred to as the CEP, ushers in a new era for the energy storage industry. The CEP for the first time in EU law formally recognises energy storage as one of the key players in the energy system and seeks to address the main barriers that have hampered storage deployment.

Clean Energy Package: game changer for storage?

The CEP is undoubtedly positive for the storage sector. By establishing a binding renewables target of 32% by 2030 – along with targets for renewables in transport, heating and cooling – the package sets a high level of ambition that can only be achieved with the widespread deployment of flexibility solutions such as storage.

Within the CEP, the recast Electricity Directive and Regulation tackle some of the most pressing challenges for storage technologies. First of all, they establish a definition for energy storage that covers all of the different technologies: pumped hydro storage, power-to-gas, power-to-heat, liquid air, batteries, supercapacitors, flywheels and others. This technology-neutral definition ensures that both current technologies and those that may be developed in the future are covered by the legislative framework.

Second, the Clean Energy Package clarifies the important issue of regulated entities owning and operating storage facilities. As a general rule, transmission and distribution system operations (TSOs and DSOs) should not own and operate storage, unless they are considered "fully integrated network components". However, in situations where there is no market party willing to build a storage device, the National Regulatory Authority (NRA) may introduce a derogation. Prior to the CEP, the lack of clarity on ownership of storage held back the development of storage devices; addressing this point therefore represents an important step forward.

The CEP also focuses on the evolving role of TSOs and DSOs more broadly: TSOs and DSOs must consider energy storage in their network planning and are encouraged to move towards market-based tendering of flexibility services as an alternative to grid expansion. This will allow energy storage to access more revenue streams, building a more robust business case and creating a level playing field between the different flexibility options.

In addition, the CEP emphasises the changing role of consumers in the energy system. Instead of being passive players in the energy system, consumers can choose to play an active role, deploying renewables and storage and participating in different electricity markets. The package formally recognises the right of "active customers" and "citizens energy communities" to own and operate energy storage devices. These customers and communities should be able to offer the flexibility of their storage devices to the grid, including via aggregators.

Credit: Belectric

The role of energy storage facilities in providing grid services is more clearly defined in the Clean Energy Package

Although the CEP is a significant step forward for the industry, it does not address all of the issues that are holding back storage deployment. For instance, energy storage will require at least some investment certainty in the form of long-term contracts for storage services. Yet the CEP limits the duration of balancing services, which could reduce investment certainty. This means that there are ever fewer longer-term revenue streams on which storage operators – and investors – can rely.

Another key issue is that grid fees, taxes and tariffs applied to energy storage may be higher than on other devices, as storage is sometimes taxed when 'consuming' electricity and then again when 'generating' electricity. This point is not adequately addressed in the CEP, since taxation remains an EU member state competence.

Beyond the CEP: new policy initiatives and challenges for storage

Although the CEP addresses some of the key high-level principles that are needed to formalise the role of energy storage and ensure access to new revenue streams, there are many more topics that are still up for discussion.

One key challenge is that the implementation of the CEP provisions may not be uniform across all member states. Some markets that are now closed to energy storage technologies (for example, the Czech Republic, which does not allow stand-alone grid-scale storage facilities to be built), may still lag behind in terms of implementing the package. Urging governments to implement the CEP as quickly as possible is therefore a key priority in order to have a harmonised EU market.

While CEP implementation is important, there are also many new EU policy initiatives that can benefit storage. Next year, the Commission is expected to propose changes to the EU's gas legislation. The 'Gas Package' will cover a range of gas market design issues, notably the role of power-to-gas. Definition of renewable and low-carbon gases, guarantees of origin and certification schemes will have an important impact on the storage sector [2].

Over the past two years, there has also been a flurry of Commission activity focused on supporting the batteries sector in Europe. Commissioner Maroš Šefčovič, vice-president of the European Commission in charge of the energy union, has repeatedly emphasised the strategic importance of a strong EU value chain for batteries. At his initiative, a European Battery Alliance was established to enhance collaboration between industry and policymakers. This has led to a number of other activities including a proposal for sustainability criteria for batteries, a battery working group in the European Parliament, and additional funding for battery R&D projects.

This year the European institutions have also been debating the EU's 2050 strategy for greenhouse gas emissions reductions. The Commission's proposal, issued in November 2018, envisaged that power generation be fully decarbonised by 2050, with a share of variable renewables in gross electricity generation of 81-85% [3].

The Commission's analysis of the different options to reach this target underlined the vital role of energy storage: stationary storage use is expected to increase from about 30TWh today to 70TWh in 2030 and 170-270TWh in 2050 to achieve 80% greenhouse gas reductions compared to 1990 levels. This is a massive increase in energy storage deployments, which will require significant investments in the sector. However, this analysis only considers some storage technologies and does not quantify the flexibility that can be provided by behind-the-meter storage or – potentially – smart charging and vehicle-to-grid solutions.

The discussion about this strategy is still ongoing, as the growing number of EU Member States that support a target of net-zero emissions by 2050 have been blocked by a minority. There is also a debate about potentially revising the 2030 greenhouse gas emissions reduction targets to reflect a higher level of ambition.

For behind-the-meter storage, there are ongoing discussions in various member states about the grid fees and tariffs that customers should pay, and several countries and regions are considering incentive schemes for storage behind-the-meter. Another interesting development is the Smart Readiness Indicator [4], one of the proposals contained in the Energy Performance of Buildings Directive (part of the CEP). European policymakers are currently defining the methodology to assess the smart readiness of buildings, which will include measuring the ability of buildings to provide flexibility to the grid and support electric vehicle charging. Deployed alongside energy performance certificates, the smart readiness indicator of buildings could be a valuable way to communicate the added value of smart energy technologies – including energy storage – to consumers.

Finally, there are also developments related to DSO-TSO cooperation, for example to define new services such as congestion management that could be provided by services, and around the EU electricity network codes. The revision of the grid connection codes to include battery storage and other storage technologies (of which currently only pumped hydro storage is included in the codes) is an important step that could help create a more harmonised regulatory framework for storage across the EU.

What's next for storage?

While the CEP is a big success for the storage industry, now is not the time to rest on one's laurels. As the energy storage industry matures, and as the energy transition accelerates, engagement with policymakers will be essential to ensure that the right policies are put in place to support storage deployments. A few key risks are worth mentioning, which could derail some of the advancements made in recent years.

One risk, as highlighted above, is the tendency of EU policymakers to discourage longer-term contracts for flexibility services, which could reduce certainty for energy storage investors. Another risk is that policymakers tend to pick winners and losers among the technologies. For instance, significant attention is paid to li-ion batteries and hydrogen, potentially shutting out some of the other promising energy storage technologies that will be needed for the energy transition.

Not only is the diversity of energy storage technologies not considered, but also the diversity of services storage can offer is difficult for policymakers to take into account. This is noticeable, for instance, when looking at the modelling used by EU policymakers to support the 2050 targets, or the discussions around the Smart Readiness Indicator for buildings.

Since the European elections in May, new members of the European Parliament have come to Brussels, and a new College of Commissioners is being formed to take up its activities in November 2019. There is no guarantee that these policymakers will continue the positive efforts of the current Commission – and, to a lesser extent, the European Parliament – when it comes to energy storage.

Continued engagement with policymakers at the local, regional, national and EU level is therefore essential to ensure that they understand the complexity of the energy storage business case and the many different services that energy storage can provide – and should, ideally, be remunerated for. Industry and policymakers must work together to design smart and effective policies to ensure that energy storage can reach the levels needed to achieve the 2030 and 2050 decarbonisation targets. ■

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Bankable and insurable energy storage: a necessary next step for renewable energy

Finance | The rapid acceleration in energy storage deployment expected over the coming years will require innovation in the quality and safety standards underpinning new battery and associated technologies. VDE's Jan Geder looks at the technical work underway to ensure the coming storage boom has firm bankability and insurability foundations


Credit: VDE

Renewable energy is taking up an increasing share in the global energy mix. Utilities, distributors and users are facing the increased need to supplement renewables with energy storage systems to tackle the intermittency of these sources and ensure stable supply. Bankability and insurability of renewables, particularly photovoltaic systems, is nowadays a common concept with clearly defined criteria and processes. As the viability and availability of energy storage becomes the crucial factor in further growth of renewable energy generation, it is necessary to ensure bankable and insurable solutions for deployment of energy storage systems. This article explores the status and outlook for bankability and insurability of battery energy storage systems.

Recent years have seen a stellar rise in the generation of electricity from renewable sources. In the first half of 2019, 47.3% of net electricity generation in Germany came from renewables [1], an increase of 9.1 percentage points (23.8%) since 2017 [2]. According to Eurostat, the share of renewables in European Union's energy mix of 2017 amounted to 17.5%, an increase by two thirds since 2007 [3]. At the same time, the share of renewable energy has been increasing in developing markets as well. This is particularly the case for PV systems, which are set to break the 100GW milestone of newly installed capacity in 2019 [4]. This is driven mainly by rapid growth in the developing markets of Latin America, Middle East and Africa.

Increasing solar capacity and its share in the overall electricity mix requires an increase in energy storage capacity. This is due to the intermittent nature of solar irradiation, which rarely corresponds to required grid demand in real time. A 2015 report by the Rocky Mountain Institute lists 13 different services that battery energy storage system can provide to the grid [5]. These services can be provided to system operators and utilities, as well as to end-customers. There is a clear distinction between centralised and distributed systems as battery systems can be placed at three different levels: at distribution level, at transmission level and behind the meter. The latter, customer-sited and most decentralised systems, are also capable of providing the largest variety of services to grid.

Stringent testing of storage technologies will be critical to the sector's future bankability

The case for bankable battery energy storage systems

Projections for Germany [6] predict that 110-190GWh of energy storage systems would need to be installed by 2050 in order to meet energy transformation goals. Based on nine different scenarios, this is divided into 70GWh of pumped storage and 40-120GWh of battery energy storage systems, and excludes heat storage and power-to-fuel systems. These storage systems would be integrated in a grid with an installed capacity of renewables between 193 and 536GW, of which 122-290GW would belong to PV systems, according to the same projections.

Battery energy storage systems play a significant role in future rural electrification in developing countries. They are namely expected to enable deployment of renewable energy-based microgrids where photovoltaic system would play the major role in power generation. Reliable battery systems would therefore eliminate the need for costly infrastructure investments aimed at connecting remote and insular areas to the grid. Furthermore, efficient and sustainable microgrids would reduce the current dependency on diesel generators and their sensitivity to the logistics of the fossil fuel supply chain and its price volatility.

Both cases mentioned above face the challenge of acquiring financing for the construction, commissioning and operation of battery systems. At the utility scale, one expects to deal with large systems on which

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the reliability and stability of the grid shall depend. In the case of microgrids, the global majority of potential implementation sites are located in developing countries, where the low purchasing power of consumers may hinder the initial investment. For both cases, it is therefore equally important to ensure high-quality technical foundations that help ensure the profitable operation of battery systems, which is crucial for enabling the financial sector to provide financing products at reasonable conditions for these systems.

What makes batteries different from solar panels?

In the timeline of renewable energy development, batteries are commonly seen as the next big thing after the success of PV at the beginning of 21st century. Cheap and reliable storage is believed to deliver a much-needed boost to the solar-powered renewables boom which is happening globally. To follow the successful path of PV deployment, battery storage also needs to become bankable, insurable and investable. Although adding battery storage to the equation does not require us to completely reinvent the ideas of bankability and insurability, it is worth noting several important technical aspects of batteries that affect and influence the financing decision-making process for energy storage.

The most obvious distinction between batteries and PV systems or wind turbines is that batteries only store energy for later consumption and do not generate power themselves. The reality of bi-directional energy flows to and from battery systems requires careful dimensioning with regards to expected load profiles on both the charge and discharge sides. Energy storage systems therefore need to be planned to operate with regards to generation and consumption characteristics of the grid. This includes accounting for future upgrades based on the grid's needs.

On the costs side, there are further differences between battery systems and PV systems. "Lithium is not silicon" is an oft-invoked saying when the long-term price prospects of lithium-ion battery systems are discussed and compared to the last two decades of price development for PV modules. In fact, the lithium-ion cell price per kilowatt-hour dropped 85% between 2010 and 2018, with an average annual decline of 20%. This happened mainly due to technical improvements on the product side (higher energy density electrodes) and the process side (larger, more efficient

Figure 1. Price per kWh of lithium-ion storage capacity adjusted to 2018 US dollars [7]

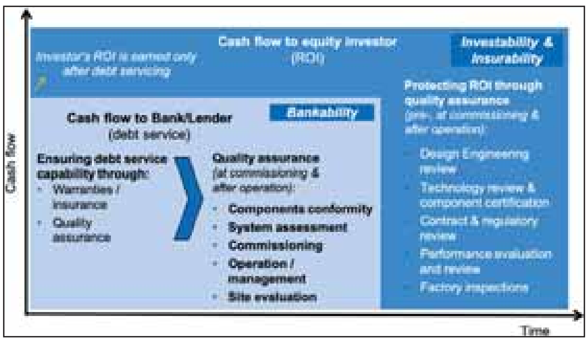
manufacturing lines). However, the rate of price decline may slow down in the future due to several factors:

- Increasing price of relatively scarce resources such as lithium and cobalt;
- Increasing demand for batteries from the electric vehicle industry;
- Consolidation of the industry with a few globally dominant manufacturers.

Parallel to improvements in energy density and price declines, there has also been a shift towards safer lithium-ion technologies. Safety of lithium-ion cells has marginally improved since their first commercialisation in the 1990s, though there is currently still no such thing as a "safe" lithium-ion battery. A state-of-the art lithium-ion battery is a thermodynamically meta-stable system whose failure modes may lead to grave consequences in the forms of explosions and fires. Recently, more than 20 battery storage system fires made headlines in South Korea [8]. These incidents caused hundreds of energy storage systems country-wide to be suspended from operation and inflicted millions of dollars' worth of damage to adjacent facilities. Investigations conducted by local authorities suggest that the fires were caused by poor site management [9].

Such prospects raise the issue of insurability of battery energy storage systems to a much higher degree than in the case of PV systems – the tendency of lithium-ion batteries to catch fire in an uncontrollable

Figure 2. Bankability and insurability of a project in terms of cash flow projection



manner may lead to much higher total damages. It is therefore critical to devise rigorous processes of safety and quality assurance in order to gain the confidence of insurance companies, banks and investors. As the track record of such processes is yet to be established, it is critical that all stakeholders get on board and enforce the best practices in design and operation of battery systems.

Development of technical criteria to support bankability and insurability

The basic idea of bankability and insurability is presented in Figure 2. Quality assurance is understood as a wide range of measures aimed at securing the technical foundations for insurability and bankability of a project. Furthermore, it is important to recognise that the quality assurance requirements of an investor or an insurer can go beyond the requirements of a lender. There are two main objectives of quality assurance with regards to project economics and financing:

1. Understanding, mitigation and control of risks in order to make the residual risks of the project acceptable for insurers and investors;
2. Performance and efficiency analysis, reviews and tracking to ensure profitability of the project.

The origins of technical risks in a battery system can be divided into four major sources: components, system design, installation site and management/operation. They affect three crucially interconnected system characteristics: safety, performance/efficiency and lifetime.

Various risk sources require different approaches to quality assurance. On the component level (e.g. battery module, power conversion system), one can rely on a large number of applicable international and national norms and standards, for example IEC 62619 for battery modules, IEC 62909 for bi-directional converters and VDE-AR-E 2510-2 for battery systems intended for low-voltage grid connection. Component conformity is the cornerstone of quality assurance and the very foundation of risk management. Basic components, such as cells, modules and auxiliary systems (e.g. cooling systems, monitoring systems) shall be tested and certified to the above mentioned standards. However, with increasing levels of component complexity, design reviews are gaining importance as a supplement to pass-or-fail tests. This is particularly true for components such as the battery management system or energy

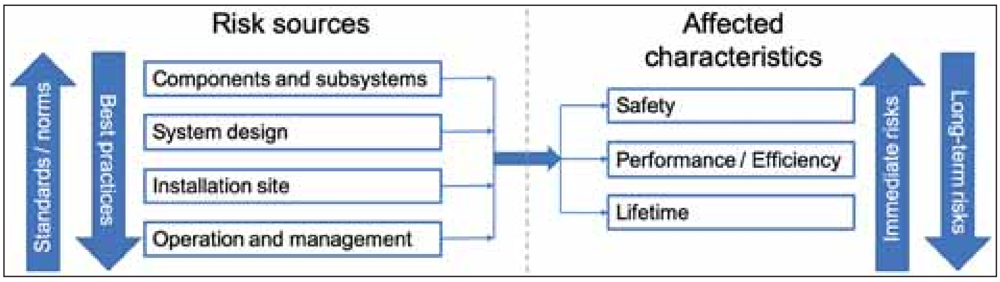


Figure 3. Visualisation of risk sources and affected system characteristics

management system, which are critical for functional safety.

Going beyond components, the complexity of quality issues surpasses the pass/fail dichotomy of the standards and related tests and reviews. As the publication of relevant international standards, such as those from the International Electrotechnical Commission (IEC), lags behind the need for quality assurance on the ground, one needs to increasingly rely on empirical "best practices" and other tailored criteria. With these, overall system design and the battery system installation site can be evaluated.

Finally, it is important to look at how the battery systems are managed on a day-to-day basis. This includes keeping the system and its environment consistently in proper condition, conducting regular maintenance, adhering to plausible risk management principles, and implementing strict control of documentation and record-keeping for the system. With proper practices, system risks are kept under control even as the system ages with time and inevitably decreases in performance.

There are several best practice documents and norms dealing with various individual segments of the above described processes. However, taking into account the lessons learned from bankability in the solar industry, it is important to take a holistic view of quality assurance for the entire system and project. A stakeholder that is looking to secure technical bankability and insurability through quality assurance would be best advised to implement the following practices into their processes:

- A guideline of compliance requirements and best practices for designing, installing and managing battery energy storage systems;
- A criteria catalogue or checklist based on the guideline that enables evaluation of each system considered;
- A procedure of inspections of system sites, preferably conducted by independent engineers, to regularly evaluate risks arising from the above-mentioned risk sources.

The described process of defining the criteria is visualised by the "VDE Quality Pyramid" as seen in Figure 4. The fundamentals (first level) are the standard market entry criteria in the form of national or international standards. These make sure that core components are compliant with basic regulations, but do not always follow the state-of-the-art developments in the market. Therefore, the test/evaluation criteria are expanded to address requirements of the highly competitive market and industry, rather than only those from the legislator/regulator point of view (second level). At the top level, tailored criteria are introduced to address the specific requirements and purpose of the project/system.

A look into the future of financially sound battery energy storage

As the demand for safe and reliable energy storage steadily follows the increase in renewable power generation, the involvement of financial institutions will become indispensable to provide the necessary financing and insurance for storage systems. Testing, inspection and certification institutions and technical consultants are developing processes and criteria to secure technical foundations for bankability and insurability of battery systems. In this case, the experience and progress with PV bankability and insurability can serve as a basis and reference point.

As was the case with PV systems in the past, many challenges lie ahead on the way to establishing a track record for reliable quality assurance for energy storage systems. Well-known safety issues of lithium-ion systems and the related pricing development are perhaps the most pertinent. On the other hand, there are many opportunities to capitalise on the lessons learned. Furthermore, battery energy storage may become even more economically attractive with the concept of repurposing used batteries from electric vehicles for stationary storage (i.e. second-life applications). Needless to say, this concept will again require stringent quality assurance and risk management tailored to the application. ■

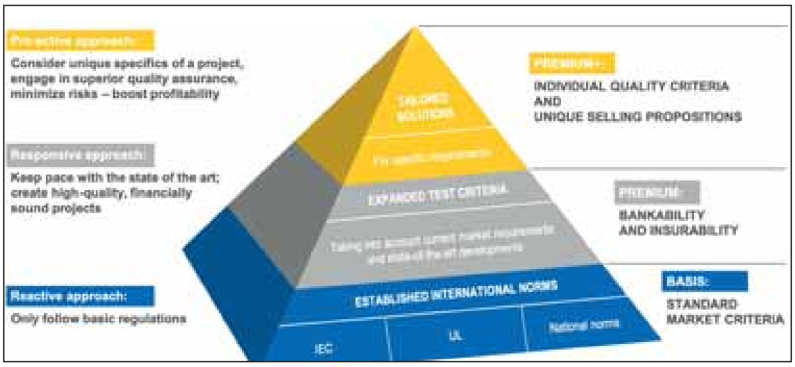


Figure 4. The VDE Quality Pyramid concept

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Batteries need to be 'renewable' too: why recycling matters now

Recycling | The huge upsurge in lithium-ion battery deployment expected over the next two decades poses a problem: what to do with cells that have reached the end of their useful life. Stefan Hogg investigates the importance of lithium recyling in the transition to a low carbon energy system

Credit: Li-Cycle

Output shred product from the first stage of Li-Cycle's resource recovery process

In 30 years since commercialisation, lithium-ion (li-ion) batteries have been used in an increasingly diverse range of products, starting from early generation handheld electronics to powering cars and buses. Additionally, these batteries are increasingly sought after for utilisation in energy storage applications, often paired with renewable energy generation. The continued decline in battery prices combined with the global trend toward energy grids being powered by renewable energy sources is predicted to increase the world's cumulative energy storage capacity to 2,857GWh by 2040 [1], a substantial increase from the current capacity of ~545MWh [2], according to recent estimates by Bloomberg New Energy Finance.

These staggering projections paint an encouraging picture for how prominent li-ion-driven energy storage applications will become in the future as the world increases its usage of renewable, clean energy sources to power energy grids worldwide. Driven increasingly by electro-mobility as well as grid-scale energy storage applications, the volume of li-ion battery cells being sold is set to surge. The graph in Figure 2 contextualises the relative volume (in tonnes) of new li-ion battery cells forecasted to be sold through to 2025.

The growing quantities of li-ion batteries being placed on the market accelerates the urgency with which the world must find an economically viable, commercial-scale recycling solution for end-of-lifecycle li-ion batteries to be recycled at a 'mega' scale. This article will take a closer look at some of the challenges that exist today within the li-ion recycling sector and where opportunities exist to overcome the current roadblocks.

Li-ion recycling industry challenges

Feed sourcing

Secondary resource recovery (i.e. recycling) has a set of unique operational challenges that need to be addressed concurrent to the development of an economic, advanced technology. For the purpose of recycling, feed materials are typically inherently distributed, making it difficult to collect a high volume of feed for a processing plant. Although the collection supply chains for some analogous industries such as lead-acid battery recycling are well established and mature by comparison, the li-ion battery recycling supply chain continues to be fluid.

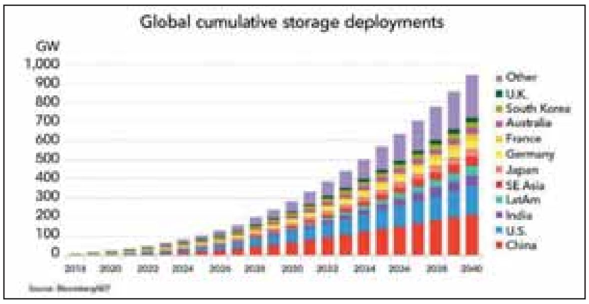

Figure 1. Global cumulative li-ion battery storage deployments. Source: BloombergNEF

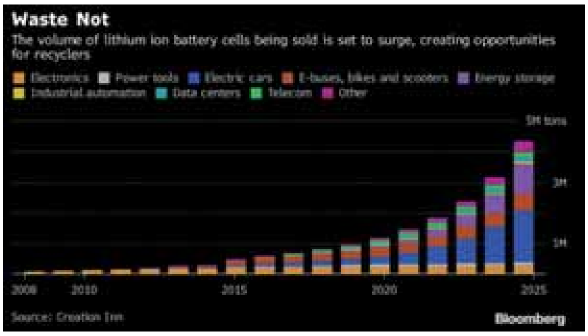

Figure 2. Global lithium-ion battery cell sales, 2008 to 2025. Source: Bloomberg and Circular Energy Storage, 2018

Spent li-ion battery sources can be broadly segmented into portable/'small format' and 'large format', which corresponds to the relative voltage of li-ion batteries (i.e. low voltage and intermediate to high voltage, respectively). Each of these types of batteries has a diverse group of stakeholders – from manufacturers, to the dealer network, recycling programmes, electronics and vehicle recyclers. In the context of the energy storage sector, its own diverse group of stakeholders exists – battery technology provider, energy storage integrator, project developer and asset owner. Managing the inherently heterogenous nature of li-ion batteries from a wide range of stakeholders remains a central challenge for companies in the li-ion resource recovery industry.

Logistics and regulations

Li-ion batteries are currently classified as Class 9 Dangerous Goods due their dual chemical and electrical hazard. Li-ion batteries can possibly undergo thermal runaway, typically resulting from internal shorting, leading to fire or explosion. There are numerous factors that can cause thermal runaway, including but not limited to overcharging, environmental conditions (e.g. extreme external temperatures) and manufacturing defects. At the onset of thermal runaway, the battery heats in seconds from room temperature to above 700°C. As part of this complex set of chemical reactions, the electrolyte solvent in lithium-ion batteries – typically alkyl carbonate-based – acts as a 'fuel' source for combustion.

Added care must also be taken when handling critical or damaged/defective batteries as there is an increased risk of thermal runaway. Specialised systems (e.g.

Genius Technology's LionGuard container for intermediate to high voltage lithium-ion batteries [3]) are typically used in tandem with non-flammable packing material to safely transport these batteries. As the overall volume of li-ion batteries increases, the quantity of critical or damaged/defective batteries is expected to increase across a broad swath of applications.

As the li-ion battery resource recovery industry is still maturing, regulations vary significantly around the world. These regulations can also change significantly from year to year, as new industry and research reports are released. As a result, it is important to keep close track of regulatory (including logistics) considerations concurrent to process development.

Safety and storage

The challenges of logistics and changing regulations typically revolve around one key factor – safety. Safety is paramount for those who handle, transport, store and process li-ion batteries, as there is a risk of thermal runaway. This raises another unique challenge for processors and consolidators, relative to the primary production of commodities and specialties.

Specifically, the safest approach is to have the lowest amount of spent li-ion batteries on site as possible, in order to mitigate the risk of a thermal runaway event occurring. However, this is contradictory to the requirement to secure significant amounts of feed for processing purposes. The development of safe storage is further complicated by the currently prominent format factor of spent li-ion batteries, i.e. portable/small format batteries (e.g. from mobile phones, laptops and other consumer products). Portable li-ion batteries are typically consolidated in drums and could be mixed with other battery types.

Upon an initial inspection, the state of all collected batteries within a single drum is not always clear (i.e. whether undamaged or damaged) and often only becomes apparent when the drums are tipped for sorting or processing. As a result, strict protocols must be implemented regarding the pallet/container spacing, total storage density and application of appropriate fire suppression systems within any li-ion battery storage space in order to mitigate the risk associated with thermal runaway and fire

Secondary resource processing challenge

From a process development standpoint, the recovery of constituents from li-ion

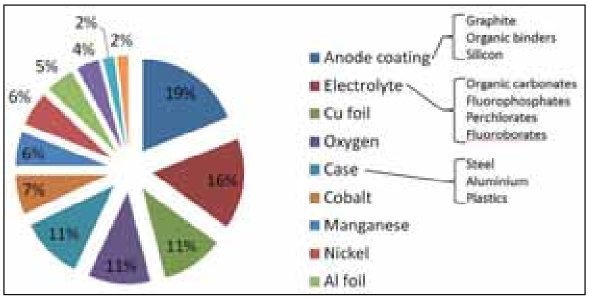

Figure 3. An example li-ion battery composition. Source: Diekmann et al

batteries presents a unique challenge compared to traditional primary metal resources due to the highly heterogeneous nature of the feed material. Currently, there are at least 14 different types of li-ion battery cathode chemistries currently existing in the market [4], each of which has even further permutations when considering specific constituents. With traditional metal resources the primary concentrate stream might have one to four elements to be recovered (e.g. copper, gold, silver and platinum). Li-ion batteries may however contain over 20 elements that demand consideration for recycling as illustrated by the example composition in Figure 3 [5].

In addition, the metal values are typically contaminated with inorganic materials, organic materials and plastics, further complicating the recycling process. To be able to separate out the valuable constituents typically requires complex process flowsheets with many individual unit operations. Under this scenario, it is critical that the physical test-work required to develop the process flowsheet is well focused and driven by techno-economic analysis.

Li-Cycle is one company with a strong focus on technology for resource recovery of end-of-lifecycle li-ion batteries. Since incorporation in 2016, Li-Cycle has developed and validated a unique process to recover 80-100% of all li-ion battery constituent materials using a two-step mechanical and hydrometallurgical system. This advanced resource recovery process, alongside concentrated efforts focused on battery sourcing from various supply chain players and a continuous prioritisation of safety, are fundamental elements supporting Li-Cycle's goal of global commercialisation of Li-Cycle Technology.

Opportunities and future outlook

It is evident that the global volume of li-ion batteries deployed in energy storage and other applications is set to increase steadily over the next two decades, underscoring the necessity for a sustainable end-of-life pathway for these batteries both now and into the future. Li-Cycle is on a mission to leverage its innovative solution to address an emerging and urgent global challenge. Li-ion batteries are increasingly powering our world and there is a need for improved technology and supply chain innovations to better recycle these batteries, and to meet the rapidly growing demand for critical and scarce battery-grade materials. Scalability, low-cost, safety and environmental sustainability are core tenets of commercialising Li-Cycle Technology. In turn, Li-Cycle seeks to enable the global transition to electro-mobility and reduce greenhouse gas emissions worldwide.

Lithium-ion batteries will continue to electrify our world, now and into the foreseeable future. As a key driver of the transition away from a carbon-based economy, li-ion batteries are integral to the opportunity to drastically reduce greenhouse gas emissions worldwide. However, to ensure a truly positive impact over their lifecycle, we must ensure a closed-loop system is in place to safely handle and recycle spent li-ion batteries at scale. This will enable the reintegration of critical battery materials into the li-ion battery supply chain and the broader economy, while preventing negative environmental and safety impacts. ■

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Can US double-up on bifacial in wake of tariff reprieve?

Bifacial | The US announced an exemption from Section 201 trade tariffs in June. But with a limited bifacial project pipeline in place and questions around supply, will the ruling really open the door to the technology? John Parnell investigates

In mid-June, the US solar industry scored a lobbying victory, winning an exemption for bifacial modules from the Section 201 trade import tariffs. The move hands an advantage to a nascent technology with little track record in the US.

With the phase-out of the investment tax credit (ITC) imminent, many developers are keen to build out as many megawatts as possible. The question is whether the most efficient way to do that is to stick to tried and tested monofacial panels or twist, and bank the rearside power, while the exemption offsets the price differential.

The exemption is an effective 25% discount versus standard modules affected by the tariff. From February 2020 that will fall to 20% before dropping to 15% in 2021 and lapsing entirely in 2022.

To take advantage though, developers will need to be ready now.

"I'm only aware of one operational [bifacial] project in the US, the Southern Oak project in Georgia," says Xiaojing Sun, a senior research analyst, at Wood Mackenzie. "The sentiment I feel talking with our clients, and a lot of our clients are EPCs and developers, is that a lot of companies are looking at [bifacial] but Georgia Power was the first mover.

Southern Oak was grid connected in February with LONGi's bifacial modules used. The finance arranged will largely ignore the rearside power in the early years of the project's life, before a 're-mortgaging' of sorts, once project-specific data has been gathered on those rearside kilowatt hours.

"Two tax equity investors I've spoken with don't really think of it as being that different from a regular monofacial solar project. They have many years building regular solar projects and they are confident that bifacial solar projects can be financed through tax equity," says Sun, who expects debt providers to be a little more cautious. Despite that, the developers she has talked with are making plans now.

"A lot of the projects our clients are considering would be coming online as early as next year and we could see a lot in 2021. The developers I've talked to are comfortable with the technology."


Credit: John Parnell

A LONGi bifacial array. The US has an opportunity to embrace bifacial solar technology thanks to recent tariff exemptions

The exemption

Gary Liardon is COO at Petersen Dean's roofing and solar consumer division. As a board director of the US Solar Energy Industries Association (SEIA) he was involved in the efforts to win the exemption. He describes the process, and ongoing lobbying work, as unpredictable.

"The current administration is more of a wildcard than administrations of the past. It's important to note that the lobbying for this didn't start six months ago, this is a piggyback on some of the original trade cases surrounding import duties. It's been ongoing for some time," reveals Liardon. "It was less a case of a laser-focussed target on this as a possible exemption versus going after a number of exemptions and this being the one that landed.

"Other exemptions are ongoing but we don't have huge confidence that we'll get other exemptions, particularly around

China, which is being targeted with duties. The exemptions are more about specific countries than specific products. The real headway there is if we can get exemptions but also to make sure tariffs aren't applied to countries that don't have them today," he adds.

With no substantial capacity for bifacial cells or modules in the US and certainly none to speak of during time period that "harm" was measured for the previous trade tariffs, opening the door to bifacial modules makes sense. Domestic manufacturing damage is minimal and US developers can exploit the benefits of the emerging technology.

"The industry is still tiptoeing around bifacial," says WoodMac's Sun. "The majority of those [projects] that have been built are in China via the Top Runner programme. They were incentivised. That means a lot of the project knowhow is in China and the US is a relative newcomer. When things are new it's reasonable for people to demonstrate a little caution."

With the exemption in place and the ITC sunset, Sun believes the stars could be aligning nicely for an initial rollout that will pave the way beyond 2022.

"The next two years we'll see it become that bit more normal to developers and financiers. It could pave the way for the normalisation of bifacial post-2022," she suggests.

"The more bifacial products there are the more comfortable people will be with the technology, even after the 201 tariffs have gone," she says. The question of how much gain to factor in from the rearside is a nice problem to have. Sun says if developers and lenders can build confidence in a gain of even 5%, it will represent great progress.

In the immediate wake of the exemption, Joe Song, director of project operations at developer Sol Systems was not confident of an immediate bump for bifacial.

"It's important to note that just because an exemption was put in place, it will not result in a sudden increase in product availability for the next nine to 12 months. We still face a supply-constrained market, which means pricing is unlikely to drop meaningfully," he told PV Tech in June.

But Sun believes that as the utility solar market swells in the US, and the new Chinese subsidy regime kicks in, there are opportunities for bifacial.

"The bifacial exemption from the 201 tariffs will have a pretty significant impact on utility-scale solar. That's the main application and where the excitement is that we hear from our clients. The utility-scale market will be 6-7GW this year and higher again in 2020," she says.

"You need to keep in mind that there is also a step-down in the 201 tariffs and by the end of four years they will go away completely. That means the advantage of the exemption can only last two and half years then we're back to a level playing field. But I think those two years are enough for utility-scale developers to jump on the opportunity as those two years also coincide with the ITC step-downs and the rush to build."

China: shifting supply, sagging demand

Tackling the supply problem that Song highlights requires a more in-depth look not in the US but in China.

With China's old subsidy regime sidelined, support for bifacial solar is now minimal. The new system saw developers bid for a premium over and above the benchmark price in each area. With the result not out until earlier this summer, they face very tight construction deadlines before automatic step-downs in the support they receive begin to chip away at project economics.

Sun expects this will see developers looking to balance capex and high performance but not adopting a pure focus on levelised cost of electricity (LCOE): "I think that means we'll see a lot of mono-PERC, that's the sweet spot; I'm not so bullish about bifacial in China without the Top Runner programme, however."

With solar products from mainland China facing section 201 and section 301 tariffs, Sun expects some existing mono-PERC capacity in Southeast Asia to be converted to bifacial.

"It is not a very difficult process, it can be done in two to four months. The exemption came out in mid-June and we're likely to see from 2020 more bifacial products in the US from Chinese companies that can circumvent both 201 and 301 tariffs," says Sun. That would bolster the volume available to the US market where suppliers could expect to receive a higher price than at home.

But the US won't have an entirely clear run at that capacity. Sun says the biggest pipeline for bifacial projects right now is in Latin America. If those are financed and shovel ready before US projects, they might find themselves at the back of that queue. Bifacial projects are finding their way onto rooftops in Malaysia, the green fields of England's North West and sections of the massive Benban solar park complex in Egypt. Momentum is growing and the US has an opportunity to embed bifacial knowhow and build a bank of project data in good time for the potential end of the ITC. It should grab it with both hands. ■

Bifacial rooftop prospects looking up

Rooftops are not the obvious place for bifacial modules to make an early mark but PetersenDean's Gary Liardon believes there is an opportunity brewing in California.

From 2020 all new homes in California will need to include solar one way or another. The combination of smaller plot footprints and changing preferences in architectural style is opening the door to bifacial modules.

"From a roofing efficiency standpoint, it's driven by design," explains Liardon. "The traditional Santa Barbara-style housing has moved towards something more contemporary, sleeker lines, and that lends itself to these very simple rooflines, so were seeing more use of low-slope roofing with this reflective membrane and perhaps small portions in tiles. But the trend is for the primary functioning part of the roof to be low-slope.

The door is opening for bifacial modules on solar rooftops in California

Latin America's moment in the sun

Emerging markets | The global solar boom is taking foreign players to Brazil and Mexico but the journey may not be for the faint hearted. Approached by José Rojo, operators of Latin America's top two markets are keen to dispel myths of a region they say entails risks but also opportunities

Credit: Scatec Solar

Despite political headwinds, PV in Brazil continues to enjoy high-level support, reflecting its huge potential in the country

"With PV panels we will spend zero … and we will still inject the surplus energy into the grid … This is a very smart project and a very welcome one." Asked to identify which Latin American head of state uttered these words in 2019, few Western solar observers would likely guess it was Brazilian president Jair Bolsonaro. The former army captain who threatened to withdraw Brazil from the Paris Agreement on climate change, build an Amazon highway and expel foreign green NGOs is also, it turns out, an outspoken champion of one of the world's key low-carbon technologies.

To those raising their eyebrows in disbelief, local solar body ABSOLAR urges to look again. When *PV Tech Power* catches up with the association's CEO Rodrigo Sauaia at Intersolar 2019, he is keen to bust a "myth" he says remains apparent. "Some of the people I meet talk about Brazil's tough politics after the elections," he says. "There may be scepticism with climate policy but this is a liberal government interested in efficiency and competitiveness. They've come to office with an open mind, to hear what is actually going on and act based on technical knowledge, not political influence."

Decisions to date do suggest solar is warmly viewed among those Sauaia describes as "deep-knowledge electricity specialists" in the government. Bolsonaro has so far found the time to cut the red ribbon of a floating PV plant in the northeast, personally spearhead a scheme where solar will power a major water transfer – see the statements opening this feature – and amend the so-called A-6 power auction scheme to ensure solar can take part. "It's a clear result of the new mindset," says Sauaia. "The government saw that adding PV [to A-6] would reduce tariffs for end consumers."

Solar's average prices of BRL67.48/MWh (around US$17.5/MWh) at the separate renewable-only A-4 tender, held two months after the A-6 inclusion, can only have strengthened Bolsonaro's faith in PV's cost-cutting potential. The vastly oversubscribed auction further cemented Brazil's standing in the eyes of global solar, already busy making major inroads – from Lightsource BP's 1.9GW to Solatio's 7GW – in a market that doubled installed PV capacity to 2GW-plus last year. "Solar's future looks very bright in Brazil," says Sauaia. "The shift in the following decade will be significant."

Credit: Palácio do Planalto/Flickr

Faith in solar's cost-cutting potential has made an industry champion of green sceptic Jair Bolsonaro

Political curves ahead for Mexican solar

Some 7,000 miles to Brazil's northwest, the headlines faced by Mexican solar are decidedly bleaker. Last year's rise to power of left-wing president Andrés Manuel Lopez Obrador – widely known under the AMLO acronym – was followed this year by the cancellation of Mexico's renewable auction, a core pillar of the energy reform enacted by his pro-market predecessor Enrique Peña Nieto. The move by state-run utility CFE in April to re-open auction contracts it said it had been "forced" to enter did little to dispel the misgivings of renewable players.

Some on the ground are feeling the bite of political volatility. The comings and goings of Mexico's energy policy – from statist approach to liberalisation, followed by an abrupt standstill – are written all over the double-digit-megawatt pipeline a certain firm has tried, without success, to deploy for years. Approached by *PV Tech Power*, the firm explains it bought the schemes in the mid-2010s but failed to reap auction contracts as the projects could not outcompete larger, clustered rivals. The ensuing expiry of interconnection permits pushed the pipeline into a development limbo, the firm adds.

"We've tried to get a deferment but authorities, especially the CFE, have refused," says a project manager at the developer. "If the deadline had been extended, it's likely the projects would have been deployed as there was a window in 2018, with huge investor interest in the market." According to the firm, it is currently rethinking its strategy with its stranded pipeline, eyeing the possibility of finding a major final user. "But we're still waiting as Mexico seems rather stuck since the government change," they add. "There's not a clear outlook of how things might evolve."

Nicolás Escallón of private equity outfit Actis similarly echoes the talk of uncertainty after the auction stalemate. "It's true there are currently elements that are less favourable, and which are triggering uncertainty in the renewable sector," the Mexico City-based energy director tells this publication on his way to the opening of 129MW Guajiro this summer, a PV plant part of Actis's Latin American platform Atlas Renewable Energy. "The impact was on the whole country. Auctions were Mexico's highly efficient way to grow renewables at scale."

Debunking the worse-under-AMLO narrative

Political headwinds or not, Mexican solar remains in ruddy health. From Engie's 746MW to Neoen's 375MW, Northland's 130MW, EDF's 119.6MW and Risen Energy's 117MW, the list of utility-scale ventures marking building and funding milestones so far this year shows shovels are ploughing on ahead regardless of who occupies Mexico City's Palacio Nacional. One of the latest newsworthy moves – the powering-up of Zuma Energia's 162MWp La Orejana – took place with a minister in attendance. Has AMLO's power – or indeed his will – to undo renewable progress been overstated?

This year's linking of Atlas' auction-backed 129MW Guajiro solar plant followed Mexico's decision to put further tenders on hold

Marco Nieto-Vázquez, partner and director of economics at Baker McKenzie Mexico, believes some of the headlines written since last December are hyperbolic. "This is like any other handover – a new government comes in, halts things while prior policies are revised. It's a learning curve, where authorities are trying to understand the new dynamic," he says. "From our end, what we try is monitoring what the government does, not what it says and so far I don't see the dramatic change some talk about – on the whole, this energy market continues to operate as before."

Nieto-Vázquez plays down the actual impacts of the auction freeze. "It's true there was a certain inertia carrying over [from Peña Nieto's auction calendar] but a new government has come in, with the right, I expect, to revise things," he argues. He brushes off claims that the postponement will put sticks in the wheels of Mexico's renewable progress, noting that arranging future tenders is compulsory for national electricity market operator CENACE. "Auctions are the only way energy can be purchased to meet basic supply," he says. "What we have now is a just a delay."

The partner at Baker McKenzie concedes state utility, CFE – which this year branded solar and wind as "very expensive" – has been "ideological" in its approach. However, he says his firm has not witnessed the reopening of any old auction contract by CFE despite its promises in that direction. Making good on its threat could land the utility into trouble, Nieto-Vázquez says. "One of the president's priorities is ensuring power prices remain low," he adds. "If by trying to reconquer power generation and transmission CFE is unable to offer competitive tariffs, there will be problems."

Auctions will only take you so far

Despite their seemingly disparate political outlooks, Brazilian and Mexican solar face a shared obstacle – project finance – on their way to mass-scale success. However eye-catching, auction victories do not guarantee funding: at a respective 5.2GW and 4.3GW, Brazil and Mexico ranked first and third on this year's BloombergNEF global charts for countries with the largest volumes of auction-backed renewables in need of finance. Argentina (2.7GW) and Chile (2.6GW) placed fourth and fifth; India, second with 4.7GW, was the only non-Latin American top-five entry.

That financing is the one fly in the ointment of an otherwise promising Latin American solar future is echoed by some of the newcomers. Pablo Otin, CEO of Powertis, a firm that entered Brazil in early 2018, says the reliance on the country's two main financiers, BNB and BNDES, can somewhat limit developers' options despite both banks' "good work" in adapting to a changing market. Volatility around currency – which CEO Otin describes as one of Brazil's defining features – complicates turning to foreign financiers unless they have the ability to transact in Brazilian reais, he adds.

Powertis, the sister business to Spanish group Soltec Trackers, is working on a 770MW AC/1GW DC solar pipeline in Brazil's central region. According to Otin, the tentative plan is to start building two clusters of 90MW in H1 2020, with the remainder – including a 500MW hub – following in 2021. Powertis, its CEO explains, steered clear of July's renewable A-4 tender after observing the auction was small yet oversubscribed. Accordingly, the firm's participation in the A-6 tender later in 2019 will be decided by how much capacity is on offer, Otin adds.

However large, the five other A-4 and A-6 auctions pencilled in until 2021 cannot sate the global appetite for Brazilian solar. The numbers are dizzying: PV bids of 26.2GW were tabled for this year's A-4 auction alone, of which just over 200MW was awarded. As ABSOLAR's Sauaia notes, official stats place Brazil's technical solar potential at an astounding 28.5TWh, 178 times the size of the country's entire power matrix. Even if doubled to 2GW as ABSOLAR recommends, annual auction contracted volumes cannot hope to fill that gap. Can a Latin American PPA revolution save the day?

Cracking the Latin American PPA code

Those still classifying Brazilian and Mexican solar as "emerging" might find that either market is, as far as the industry's three-letter obsession is concerned, more advanced than headlines might suggest. In Brazil, the talk is now of a PPA-driven "free" electricity market, able to accommodate domestic and foreign PV interest in volumes no auction can match. According to ABSOLAR's estimates, the pipeline of direct solar purchases being negotiated with large industrial and commercial customers reached 2GW this year.

Powertis, it turns out, is among those driving the momentum. The firm, CEO Otin reports, has executed PPAs for its entire 1GW solar pipeline and has seen "significant volumes" being inked by other solar players. "There may be some reservations around Brazilian PPAs more broadly but our belief is – as evidence continues to emerge that these PPAs are bankable – that there's demand for them from both off-takers and investors, and that once price-adjusted returns match expectations from the investment community, the free market will skyrocket," he says

According to ABSOLAR's Sauaia, the PV body's priorities for the new PPA era are twofold. First is de-risking the short-term deals seen in today's market – average lifespans range from three to 10 years, the CEO says – by engaging with financiers, and replicating the auction-plus-unregulated mixed approach some wind players are already following. Second, Sauaia explains, is slashing red tape. "Free-market schemes face more hurdles than regulated peers, such as for instance slightly stricter environmental requirements," he says. "We're trying to equalise conditions."

The long shadow of grid u-turns

For Mexican players, private PPAs offer today a chance to extricate part of one's revenues from the grip of political volatility. Baker McKenzie's Nieto-Vázquez says his firm has advised during various PPA negotiations – representing off-takers, for the most part – at prices he describes as "competitive". Quizzed over timeframes, the partner explains the deals seen to date remain fairly short-lived. "There's often an explanation, though," he says. "Some firms can self-finance and thus have little incentive for longer PPAs."

Nieto-Vázquez does foresee trouble for Mexico's PPA scene if grids do not keep up with a swelling development pipeline. "Solar may be very competitive but if transmission is not promoted at the same speed, energy prices will be high, impacting on end consumers," he says, pointing at AMLO's axing this year of two major transmission projects in Baja California and Oaxaca. Actis's Escallón says the market needs "clarity" after the cancellation, noting the rise of grid bottlenecks. Much-needed upgrades would represent a "great investment opportunity" if the government allows it, he adds.

"As ideological as the government may yet become, energy will be needed and solar's costs are very attractive"

For its part, Brazil's grid may have been spared from high-profile expansion u-turns but is not challenge-free. According to Sauaia, ABSOLAR sees "room for improvement" with grid bureaucracy and is lobbying to ensure auction-backed projects are not automatically prioritised for connection points as per the current rules. However, he argues, the overall system does not face the congestion risks plaguing Spain and other global solar hotspots. "There's been good work interconnecting practically the entire country around a single operator," he says. "A well-distributed solar resource means PV can target states with points available – it's an advantage."

Latin America's hour

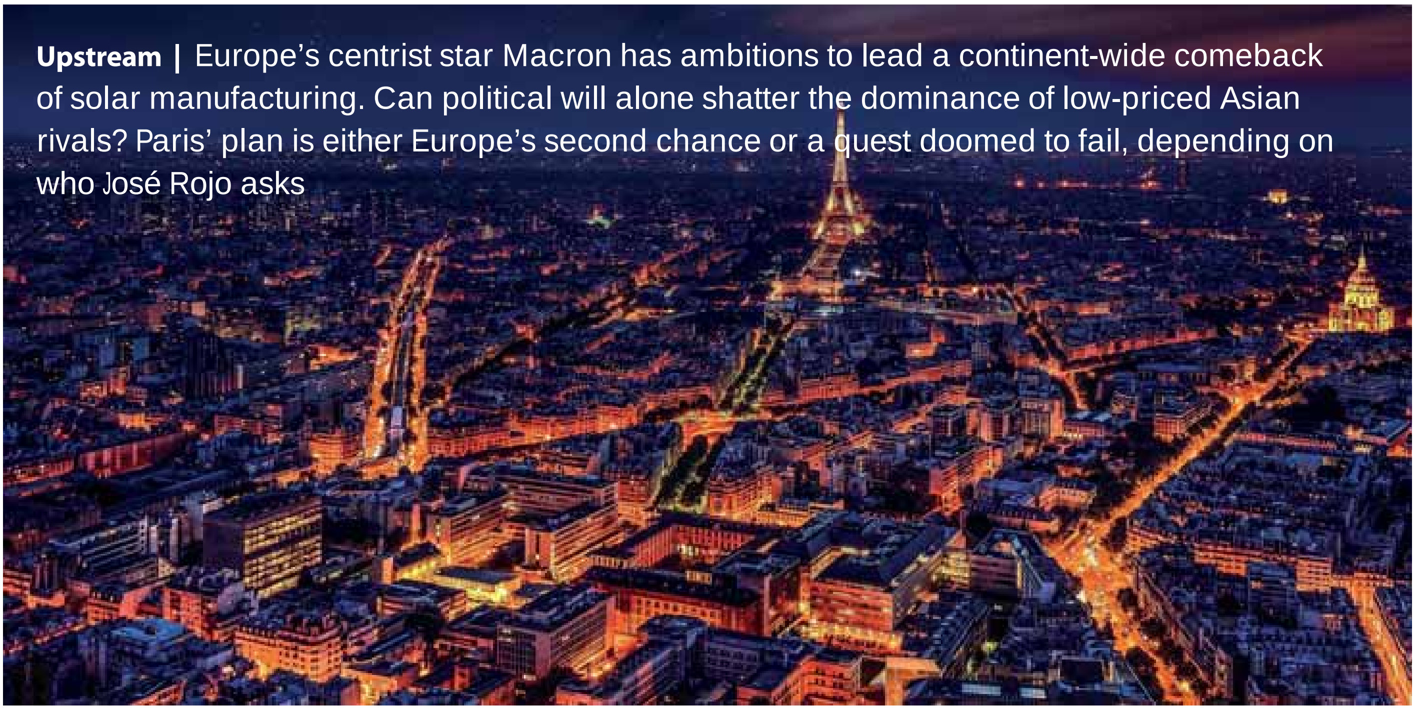
Coupled with the PV cost plunges observed worldwide, Mexico's and Brazil's mix of strong solar resource and rising power appetite from a changing society looks set to guarantee PV a role in both countries' future. A cursory glance at media headlines may create assumptions that the industry will be politically safer in Brazil but the reality may be more nuanced. Finding the time to open Zuma Energía's 162MWp La Orejana PV plant in mid-August, Mexico's Energy minister Rocío Nahle stressed AMLO's new renewable policy will not be "constrained, compressed nor inhibited", just "different". Mexico will continue walking towards clean energy, albeit at a "responsible" and "orderly" pace, Nahle added.

The clearest takeaway to emerge after hours of conversation with local experts is that making the most of Latin America's multifaceted solar markets will require challenging one's preconceptions. Interviewees acknowledge the region requires some acclimatising – as ABSOLAR's Sauaia concedes, Brazil is "not for beginners" – but all urge to rethink risk perceptions. "Brazil's electricity system and regulatory framework are both very well run. The grid's development is far superior to many other states," says Powertis' Otin when asked to compare the country with the firm's home market of Spain. "The country has been in the renewable business for over a decade and has learned a lot."

The uncertainty Mexican players have learned to live with has not majorly dented their faith, either. "This is Latin America's second largest market and one of the most attractive," says Actis's Escallón, who advises PV players to nail environmental and social aspects to ensure differentiation in a low-entry-barrier industry. Even the developer of the stranded Mexican pipeline feels bullish. "We will still bet on Mexico," says the project manager approached by *PV Tech Power*. "Foreign investors might not be that well-disposed today but it's still a great time for us developers to take up positions, map out the best spots for projects and wait for the right time to jump in meaningfully."

The parting words of Baker McKenzie's Nieto-Vázquez could easily resonate with firms keen on Latin America's potential, but wary of the volatility. "The big problem I see today is many developers believe the way they operated before AMLO is the only way, they see everything as a risk and struggle to adapt to the new reality. We must accept that things can never be the same," he says. "As ideological as the government may yet become, energy will be needed and solar's costs are very attractive. It's time to be flexible, to listen beyond the show in the media, to realise that change does not mean opportunities are gone." ■

France's improbable quest to revive EU solar makers



Credit: Walkerssk/Pixabay

The vast to-do list assembled by Emmanuel Macron in his first two years as French president illustrates the 41-year-old centrist's appetite for insurmountable causes. Take his controversial structural reforms to breathe new life into France's stagnant economy, his proposals for an EU finance minister and Eurozone budget to fuel a "European renaissance", as well as his calls for a dedicated global bank to combat global warming.

However niche, or unnoticed beyond the PV ranks, the crusade his government launched this year to revive solar manufacturing could prove no less daunting. The pledge to bring back upstream "champions" home and abroad, part of a broader reindustrialisation blueprint, comes underpinned by a rather optimistic premise: European manufacturing could regain ground lost to Asia in recent years if only government and industry pushed together on policy and research.

Outside the confines of abstract policymaking, the day-to-day reality of European PV makers remains bleak, however. The phase-out of EU tariffs for Chinese imports devastated the ecosystem, and the intervening months have done little to improve matters. The dominance of JinkoSolar and other Asian players over European peers was paraded in full view at this year's Intersolar. France-led or otherwise, has the quest to rescue European manufacturing come too late?

The window of Europe's downstream boom

While bold in ambitions, France's plan is light on specifics. Led by ministers Bruno Le Maire (economy) and François de Rugy (environment), the government vows to foster French and EU legislation to unlock large-scale funding for PV manufacturing. From EDF to Engie and PhotoWatt, the industry chips in by mapping out best practices and disruptive technologies. Both sides commit to a dilated timeframe – 10 years – for the plan to deliver a tangible return of industrial champions.

The lack of small print has not stopped some from viewing France's plan positively. "I'm very pleased that France is taking the lead for Europe," says Dr. Andreas W. Bett, director of Fraunhofer ISE, who describes Macron's support as "very important" to the cause. Recent analysis by his employer revealed cost differences between Europe and Asia have become very small. "Europe lost the battle in the past but there's a second race coming," he tells *PV Tech Power*. "It gives me hope."

France under its president, Emmanuel Macron, is looking to lead a revival of Europe's solar manufacturing industry

Bett believes the current boom in Europe's solar downstream means 2019 is ideal to restart manufacturing. In this, he is mirrored by Walburga Hemetsberger, CEO of trade body SolarPower Europe (SPE). "Our figures point at 36% installation growth in 2018 and even faster deployment in years to come," she comments. "We really are in a new era of growth, and with demand spurring, we think it is a good basis for European manufacturing to gain ground."

Bett acknowledges European success will require size – a major PV maker supporting an initial 1GW or so would be essential, he agrees – but believes interest is building as the economic case of local production becomes clearer to investors. For her part, Hemetsberger too thinks investor attention is mounting and urges EU policymakers to boost the momentum with push measures. Tax incentives, lower administrative barriers and funding guarantees from EU bank EIB could all help, she says.

A tough business to be in

Not all are equally convinced that Macron's upstream crusade will be successful, or at

> "If enough people put money into it perhaps it can succeed, but what is the point of putting so much effort if it could be costlier that just importing the modules? Solar manufacturing is a pretty dismal business to be in. Half the companies I've ever written about have gone bankrupt"

all desirable. "To be honest, I don't think it makes sense to manufacture solar in Europe, I don't see much of a strategic advantage to it," Jenny Chase, solar analyst at BloombergNEF (BNEF), tells *PV Tech Power*. "PV manufacturing is not necessarily a high-technology sector any more. Does it really create the kinds of jobs that Europeans want?"

Asked whether France could deliver its blueprint if enough people rally behind it, Chase appears sceptical. "I mean, it's probably feasible – if people put enough money into it perhaps it can succeed, but what is the point of putting in so much effort if it could be costlier than just importing the modules?" she ponders. "The other problem is solar manufacturing is a pretty dismal business to be in. Half the companies I've ever written about have gone bankrupt."

Recent events appear to underscore Chase's bleak outlook. Switzerland's ABB Group was so keen to part ways with solar inverters it agreed in July to pay US$470 million to sell its unit to Italian maker FIMER. Contacted by PV Tech Power, ABB spokesperson Daniel Smith linked the decision to falling global inverter demand, coupled with "severe" price pressure from China. The firm's retreat was likely hastened by its discovery of hundreds of millions worth of warranties owed to customers by Power-One, an inverter maker it had bought in 2013.

And yet – not all have pulled the plug. There is inverter maker SMA Solar, as well as module specialists SolarWatt and Enel's 3SUN. RECOM, Europe's self-styled largest solar manufacturer, is too ploughing on through cell factories in France and abroad. As Chase notes, Germany's Wacker remains "hugely competitive" but is vulnerable, via the panel-making countries it exports its polysilicon into, to tariff impacts. Its 2018 financial results – with polysilicon sales dropping by 27% where they rose by 10% for chemicals – were telling of the challenges ahead.

A clean slate for Europe's coal heartlands

By the time France arrived to the cause, another player had already spent months lobbying for the renaissance of European solar makers. Last September, Fraunhofer's Bett and others launched the European Solar Manufacturing Council (ESMC) to refloat the industry after the minimum import price (MIP) debacle. At its heart lies a vision: the investment of €1.935 billion to set up a 10GW wafer-to-module production line in Europe that would create 7,500 new jobs across the continent.

Before it gets that far, the ambitious roadmap must confront the tough reality painted by statistics. The latest available figures from IRENA, going back three years, show that Chinese players vastly dominated their European peers even while the latter still operated from behind the safety of EU import duties: in 2016, China's €6 billion solar net trade surplus vastly towered over that of Germany, while the UK actually ran a deficit.

That Germany was in the black at all, however small the margin, suggests that the original host of Intersolar should be central to any attempt to revive European manufacturing. France may be trying to lead the new push but Bett believes that all EU markets, big and small, could potentially play a role as hosts to the new industry. "I don't have any preference for now as no single region will be the answer," he says, adding that markets must be assessed on a case-by-case basis with investors.

Despite its country-agnostic take, Fraunhofer ISE does maintain that a particular European ecosystem – that of its post-industrial regions – would make an excellent home to new solar factories. Croatia and Germany's coal heartlands as well as France's nuclear hubs all face upheaval and would benefit from a second chance. "Look at France's Fessenheim, with a nuclear plant now nearing shutdown," says Bett. "Filling the gap with new technology would be a nice side-effect."

Playing up R&D, green credentials

Perhaps the card Europe ought to play to restore its battered upstream solar industry is not size, but specialisms. The continent should, according to Fraunhofer ISE, capitalise on its present status as global PV's R&D powerhouse via centres including Freiburg, INES, IPVF and ZSW. Research paragons such as the perovskite cell work of university spin-off Oxford PV, NexWafe's kerfless wafering technology and Photowatt's quasi-mono crystallisation process should all be nurtured going forward, the institute believes.

"Most innovation is already happening in Europe and there's a good chance for the continent to step in again," says Bett. "There's still much research left to do around building-integrated PV for instance, which requires changing the technology and module design." BNEF's Chase points at Intersolar as an example of Chinese firms still choosing Europe to talk business and innovate. "Europe does lead in terms of O&M, EPC so it still has a lot to say," she says. "But then again, of course, China does its own R&D too."

At a time of rising concern for renewable supply chains – including silver-hungry solar PV panels – another avenue

Credit: Photowatt

Europe still leads the way in solar technology innovation, through companies such as EDF subsidiary Photowatt

for Europe to explore is, some say, green differentiation. The continent, Fraunhofer ISE feels, should remind its downstream players that Europe-made products face stricter emission rules and do not require shipping across the globe. "If you really want to follow the high-level goal of reducing emissions, then transport CO2 must be somehow reflected," says Bett. "If more carbon taxes are adopted worldwide, then it's a logical development."

Bett believes appetite for greener components could rise as more countries – first France, then the Netherlands – start factoring panel footprint into subsidies. Europe, he adds, could seize the window by supplying the sustainable solar products the world will want but so could China if it so wishes. SPE's Hemetsberger agrees the green avenue is an opportunity but urges Europe not to explore it via legislating for sustainability mandates. "Market-based, competitive solutions would still be the more sustainable approach, I think," she says.

For her part, BNEF's Chase notes green mandates are the most likely direction of future European solar trade tariffs but remains sceptical of their value. "If mandates are rolled out EU-wide, companies may spend their money on certification, on the paperwork, rather than on making better products – it would probably just make lawyers some money," she argues. Using France's existing carbon footprint rules as example, she notes certification is not impossible, but also not trivial, for foreign players. "It essentially acts as a back-door trade barrier into France," she adds.

The revolution will be battery powered

Those interviewed see Europe's solar manufacturing future tied to that of a partner sector. That energy storage may be a good bet is recognised by France – its plan vows to foster five to seven globally successful French battery specialists in five years – but also BNEF's Chase. "Solar panels are not rocket science but batteries are a bit more nascent and interesting. The complexity, the role of software, may create more potential to keep highly paid jobs in Europe," she says, noting this year's Volkswagen-Northvolt deal to build battery factories in Sweden and Germany.

Chase also sees potential in so-called entech ventures more broadly. "Europe is pretty much leader in software to manage things like energy consumption and yet it's all relatively early-stage," she argues. As an example, she points at a heat pump with a consumption monitor she herself owns. "None of it is optimised, the economics of it depend on whether I can move electricity use to when I'm generating it," she says. "I'm actually quite disappointed at the state of it – I feel like Europe is leading and yet is nowhere where it could be."

Fraunhofer ISE's Bett acknowledges there is "strong interest" in European battery making, driven by the transport industry, and regrets that upstream solar does not enjoy the same political blessings. "When I talk to politicians they say 'bring an investor, do it yourself' but I wish there was a sense of urgency to having solar manufacturing in Europe," he says. "Our energy future will depend on these technologies and if we don't stay competitive in the long term, if we lose the knowhow, then we'll retain a political dependency on imports." ■

Credit: Engie

Energy storage could be an important partner sector for future solar manufacturing in Europe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Taiwan's PV industry seeks transformation in hard times

Business | For the past two years, Taiwan's PV manufacturers have been weathering a heavy storm prompted by shifting global demand for their wares. But as Carrie Xiao reports, government efforts to stimulate a local end market for PV is proving to be a potential lifeline

Over the past two years, Taiwan's solar industry has been thrown into a gloomy and painful period amid changes in both PV manufacturing capacity and a shifting competitive landscape, especially for cells. Leading companies once providing the world with high-quality cells have been struggling with losses and are undergoing restructuring, while Taiwan's achievements in wafers and ingots have gradually been overshadowed by companies in mainland China. As a result, Taiwan's wafer and cell shipments have plummeted with most enterprises being eliminated, phased out or transformed. The PV industry is filled with frustration.

In order to facilitate a stable transition for the struggling PV industry, the Taiwanese government has released a series of revitalisation policies. Plans such as The Electricity Act, Energy Development Guideline, Renewable Energy Development Act and so on, hope to boost Taiwan's PV industry by raising the proportion of renewable energy use and developing local end-markets.

On 12 April 2019 the revised Renewable Energy Development Act was approved by Taiwan authorities, setting the goal of deploying more than 20GW renewables by 2025. Power sources will be distributed among gas (50%), thermal power (30%) and renewable energy (20%).

These new policies have improved Taiwan's solar market environment to a certain extent, especially in the utility-scale end market, where the changes in installation can be clearly seen. By May 2019, the total installed PV capacity in Taiwan reached around 3.3GW.

The new progress has prompted many renewables enterprises and PV companies in Taiwan to initiate a strategic transformation and shift in positioning.

Transformation in pain

Taiwan's cell production ranks among the top in the world, but its module capacity is small. Many solar companies began to transfer to module manufacturing as these policy changes mentioned above created domestic demand.

The Taiwan Solar Energy Corporation (TSEC) says it boasts the largest PV module capacity in Taiwan, standing at 800MW currently, which it plans to increase to 2GW by 2020. While two years ago, the company's main business was cells. In 2018, its cell capacity was 2GW.

TSEC vice president Henry C.H. Chiang tells *PV Tech Power*: "Due to the increased competition in the mainland cell market, we are shifting our focus to modules. Through transformation last year, we have delivered 100MW modules in 2018 and are expecting further module expansions in 2019. To avoid homogeneity, we are producing differentiated modules."

Most of TSEC's customers in the past have been mainland Chinese companies. After the strategic adjustment, TSEC is striving to avoid being continuously impacted by mainland China.

Taiwanese PV equipment manufacturers such as URE are turning to project development in the face of falling international sales

"At present, we find our main business opportunities in Taiwan. Taiwan's solar companies in the past two years were having a hard time," says Chiang. "We are making adjustments and the local government has also contributed some positive ideas to support PV industry development in Taiwan; this is an opportunity for us."

Apart from cell and module manufacturing, TSEC's management team is also very interested in and has participated in the power plant business, with 300 projects under its belt as an EPC.

In comparison to the independent stand of TSEC, the United Renewable Energy Cooperation (URE), jointly established by Solar Tech, Gintech and NEO, showed the attitude of Taiwan PV players and regional governments towards the industry.

URE completed the merger nine

months ago and its main business segments are divided into three sections: cell (2.47GW/year), module (850MW/year, including 400MW in Vietnam) and PV power plant systems. In May this year, the company released the 144-cell 1,500V PEACH 400W high-efficiency solar module series, setting up efficiency cell standards in Taiwan.

The system section has also gradually established its core competitiveness. So far cumulative projects connected to the grid have exceeded 569MW and its project pipeline has almost reached 1GW.

President of URE's module business, Andy Shen, says: "Compared to the goal of cumulative installed capacity of 20GW by 2025, Taiwan's installed PV capacity is still small at present. We expect many rooftop and ground-mount plants to enter construction this year. The industry will also speed up in the next few years."

According to the financial data of URE, in May 2019 the company's revenue reached NT$2.29 billion (US$73.6 million), a 12.9% increase over previous months and a 136.6% year-on-year increase, signifying a positive development trend. The company also set up a new business unit this year to develop energy storage solutions.

When talking about future development, Shen says: "We are a company rooted in Taiwan but we are expanding into the world market."

Echoing his comments, Sascha Rossmann, vice president of WINAICO's solar division says: "If companies in Taiwan are to have more room to survive and thrive, they need to tap the local market and open up international markets."

WINAICO's PV business mainly includes module and system integration. In addition to seeking cooperation with local players, the company is also striving to develop European and Australian markets.

Rossmann expects strong growth in its Australian EPC business this year. At the same time, WINAICO has established business ties with more than 20 countries in Europe. Markets in countries such as Italy and Poland are getting stronger and module shipments in future are bound to increase.

These moves show that Taiwan's solar manufacturing industry is migrating from mid-stream to downstream businesses, with these players transforming from commercial cell manufacturers to module sellers and flexible integrated plant developers.

Power subsidies fallen by 60% in a decade, new trends in power market

Over the past decade, the feed-in tariff (FiT) in Taiwan has declined sharply, dropping by more than 60% (see chart below). The FiT for some PV systems is already lower than that for utilities, which would be highly competitive if traded on a free market.

The Renewable Energy Development Act will push Taiwan to phase out the FiT subsidy and introduce liberalised power transactions in the renewable market.

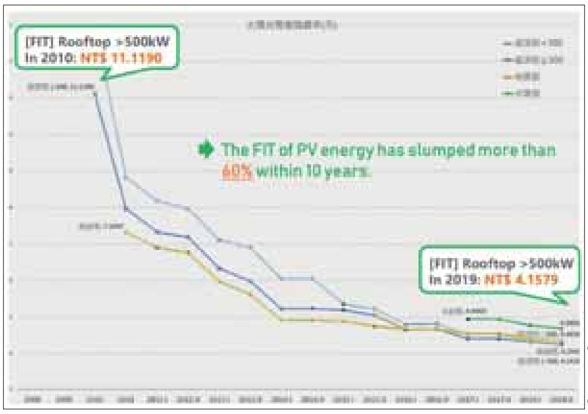
According to this law, major users of more than 800kW must have 10% of their power supplies from renewable sources, which means the needs of intensive users are expected to reach 16TWh, requiring about 12GW of PV power projects.

Nan Ya Photonics INC (NYPI) marketing director Esther M.S. Lin says: "The 10% requirement on big electricity users has created a rigid demand for renewable energy certification under the Taiwan Renewable Energy Certification scheme (T-REC)."

NYPI is mainly engaged in the solar EPC business. It has already completed 3.74MW of PV EPC projects. Lin says that in future the company will also take on more EPC projects. Lin considers that PV needs will be driven up first in areas with higher industrial power prices, such as Hsinchu, Taoyuan, Taichung and Kaohsiung, among others.

T-RECs act as proof of the use of green power. Upon certification of the Taiwan regional inspection bureau, every thousand kWhs of green electricity used is exchanged for one renewable energy voucher.

These vouchers can be used either by the holder itself or be traded with customers in need. The price is to be determined by the free market. In addition to signing wholesale power contracts with Taiwan Power Company for sale to other green power plants, all power plants holding renewable energy certificates can sell power and the voucher together. The earnings consist of the power part and the voucher part. Voucher price is also determined by the free market. The market is in short supply at present.



Source: Sinogreenergy

Figure 1. The declining FiT curve over a decade in Taiwan.

KH Chen, managing director of Sinogreenergy, is keenly aware of the policy adjustments and changes in the market. As a team leader, he made a decision to add electricity sales business to his company's activities.

As a leader in Taiwan PV power industry, Sinogreenergy is mainly engaged in power plant development, operation and EPC service. At present, its power plants already connected to the grid have reached 149.4MW with 40MW under construction and a further 109.8MW of projects in the pipeline.

Chen says: "The 2017 Electric Act proposes to allow private renewable power suppliers and retailers to sell power and T-REC directly to consumers. Amendments to the 2019 Renewable Energy Development Act have made it clear that power suppliers can sell electricity back to Taiwan Power Company at a fixed rate for 20 years. A new electricity market business model will be built, which is a new career and business opportunity for us."

On the other hand, Power Master Group, which is also deeply rooted in power plant and EPC service business, has made many attempts in exploring power plant business models and application models. In the past two years, they have been actively promoting the construction of agrivoltaic plants.

Chairman of Power Master Group Tsai Tsung-Jung says: "Over the past few years, we have completed more than 1,000 plants on government buildings, factories, farms, ground-mount plants and agrivoltaic rooftop plants. The total installed capacity reached 336.80MW, of which 140 (51MW) are agrivoltaic projects and this segment will continue to grow in future."

In view of the positive attitude of government and enterprises in Taiwan, it can be expected that in the near future, the market for liberalised solar power transactions in Taiwan will grow fast and PV power generation will become a direct beneficiary of the rise of this market.

The increase in PV installations will also help Taiwan's cell and module manufacturing industry to break through recent hard times. We are looking forward to hearing more positive news from 2019 Energy Taiwan Expo to be held in Taipei this October. ■

Digitalisation and its impact on the solar energy industry

Business processes | Digital technologies have the potential to transform the solar industry as it continues to seek greater efficiencies and lower costs. But as Dana Olson writes, a lack of both digital skills and mindset within organisations are key barriers to realising the full benefits of the technologies now available

Credit: skytron energy

The solar industry is constantly changing. Over the next 30 years, DNV GL forecasts that solar will play an integral role in the the electricity mix, with solar PV forecasted to make up 40% of electricity generation by 2050.

Advances in technology and the remarkable decrease in component cost are accelerating the progress of the solar industry. Over the past decade, we have seen the cost of solar panels fall significantly, making solar energy a competitive solution for electricity generation in many markets already. Solar is expected to be the lowest cost option for electricity in many parts of the world over the next three decades. But with this cost decrease comes mounting pressure for this industry to do more with less and find new ways to remain competitive.

As we consider the distributed nature of solar PV, the efficiency to scale from utility projects down to small residential systems has required the development of digital tools and mechanisms. From software for system design to the financial transactions that enable them, solar has demonstrated many times over that efficiency and market scale come from the utilisation of digital tools. Digital technologies have been responsible for much of the growth in the solar industry to date. As we look to the future, it is evident that digitalisation will play a significant part in solving the industry's challenges.

Defining the phases of digital transformation

Part of decoding the significance of digitalisation is to develop a well defined understanding of what this term means and how it is currently used. Digitalisation has become a trendy buzzword, often overused and poorly understood. Therefore, we must go beyond the hype to understand digital transformation like any other vital business process. Once we establish a clear understanding, it will be easier to create future roadmaps to further advance the solar industry.

We define digitisation as the process of converting information into a digital format, making it easier to preserve, access, share, and analyse data. Once we have information in digital form, we can then handle and benefit from it in ways not previously accessible.

The next phase in the process is digitalisation itself, which is the use of digital technologies to change a business process and enhance efficiency and revenue. Digital technologies include software, sensors, electronic hardware, and communications technologies. Digitalisation allows one to develop further, more sophisticated, technological tools to reduce the cost and increase the efficiency of processes, while making better, more consistent business decisions.

A suite of digital technologies is now available to the solar industry that could transform the way the industry operates

The final phase lies with digital transformation, which uses the many digital technologies along this path to change a business model and provide new revenue and value-producing opportunities. Transformation is enabled by digitisation and digitalisation to extract further value from the transition based on having the data and tools necessary to address new business opportunities. Digital transformation often substantially reduces market barriers and may increase efficiency beyond that previously possible.

DNV GL recently surveyed approximately 1,900 energy industry professionals from start-ups to large corporations – to examine their current progress in digitalisation, uncover which digital technologies are making an impact, establish what barriers the industry is facing and identify how organisations can take advantage of the many opportunities that digitalisation presents. This survey data has then been used to evaluate the digitalisation of the solar industry, especially relative to the larger energy industry as a whole.

Current progress toward digitalisation of the solar industry

Our research reveals that 40% of respondents in the solar industry have digitalisation as a core part of their publicly stated strategy. However, just 20% of the surveyed solar organisations feel more advanced than the industry in their application of digitalisation.

Overall, large companies were more likely to have digitalisation as a core

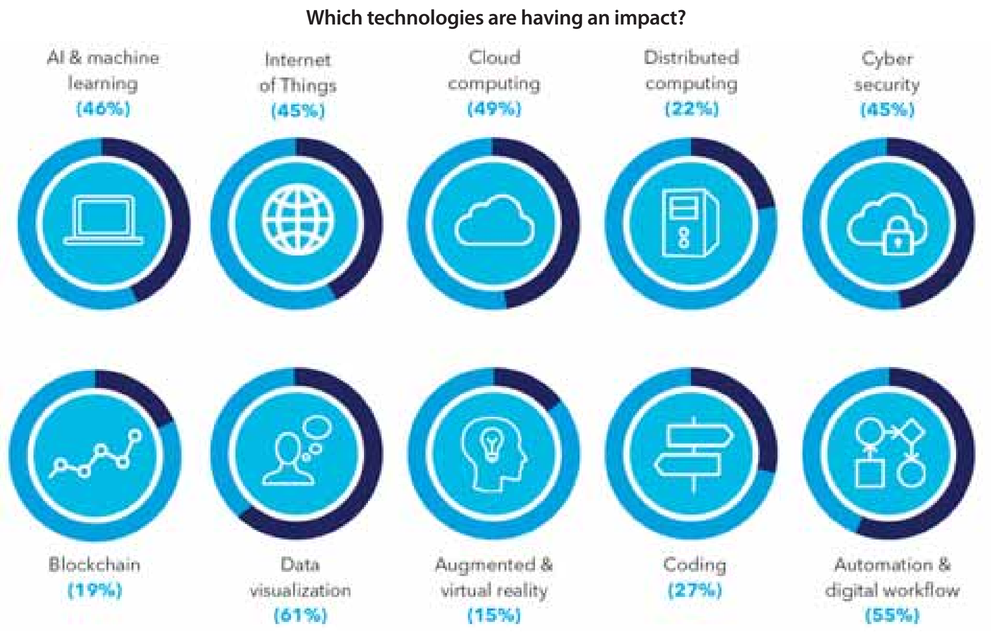


Figure 1. Percentage of respondents who said the following technologies were having an impact on their organisations

part of their public strategy, with small companies less publicly focused on digitalisation. This could indicate that large organisations are leading the way in digital maturity. However, when asked whether digitalisation was included in their internal strategy, the findings were reversed with smaller companies more focused on digitalisation internally than large organisations. This suggests that larger companies might be more concerned with creating a public digitalisation strategy than building digitalisation into their core business processes.

In today's security-conscious world, it is not surprising that cyber security is the most established focus of digitalisation. Overall, the survey found that 40% of respondents consider their organisation to be advanced in cyber security. Automation follows closely behind and is also widely implemented, with only 10% of respondents not taking advantage of its capabilities at all. The survey found the most common applications of digital workflow and automation are asset optimisation, product and process improvement, planning and strategy.

However, implementation is only one part of the picture; the real value in any technology deployment is being able to prove the impact it has on an organisation. Positively, 67% of respondents say automation and digital workflow is already having a significant impact on the energy industry, and this figure rises to 93% for large organisations.

Technology at a glance

To address value in terms of what digital tools or technologies are being assessed and implemented in the solar industry today, we reviewed the responses on the perceived value of these technologies.

Cloud computing

Our research indicates that the solar industry is leading the way when it comes to cloud computing with 35% of respondents saying their organisations were advanced in this technology. Much of this is the result of system design and layout tools, SCADA monitoring, and some financial asset management software offering cloud-based tools. The opportunities for moving more development, monitoring, O&M and finance tools to the cloud is very important to continuing to improve efficiency, lower cost and enable big data methods.

Drones

Compared to the energy industry as a whole, drones, aerial imaging, and image analysis are already having a greater impact in the solar industry. There are dozens of drone providers worldwide, who can offer lower inspection costs with higher resolution on finding panel and system defects, and support O&M practices, whilst further lowering associated inspection costs. Additional services are offered for pre-construction site surveys and inspections as well as construction monitoring. These are all supported by remote drone imaging technologies, but are further enabled by big data and machine learning methods for image analysis in the cloud.

Internet of Things

The energy industry considers IoT (Internet of Things) an important skillset to have in the future. While we are flooded with IoT innovations for our homes, significant progress is already at play in well-instrumented solar plants today; in such examples, sensors fitted to PV systems feed information back to operators on the irradiance, temperature and performance of systems, which is then coupled to detailed performance data at the inverter level. The resolution therein is increasing with the use of string inverters to better gauge the performance of strings relative to one another. Extracting the relevant data and utilising methods to inform plant and grid operators alike will lead to continuous improvements in the operation and further integration of solar assets.

Blockchain

The perceived value of blockchain technology is higher in the solar industry at 12% than the 8% across the whole energy

Big data and machine learning technologies can be applied to data collected by drones to monitor plant performance

Credit: Skycatch

industry. Blockchain technologies envision a future of decentralised energy transactions, renewable energy provenance, metering and billing. While there was substantial interest over the last few years, blockchain technologies are not yet having significant effects on the solar industry. Those that are making initial progress in this space are working toward enabling distributed, peer-to-peer marketplaces in which energy transactions can occur outside of more traditional consumer-utility models.

Technology needs in the solar industry

The solar industry is presently using a range of technologies that include a significant amount of automation enabled by digital workflows. This includes the advanced analytics, IoT and cloud computing described above. However, other opportunities will require additional investment by industry and researchers alike.

Machine learning and advanced data analytics are high-profile topics regarded as offering substantial value today and in the future. Data cleaning and algorithm training will be invaluable for the development of new tools and for establishing connections between measured and simulated performance data. Advanced data analytics, enabled by machine learning will help derive additional value from rich operational datasets and enable enhanced forecasting models.

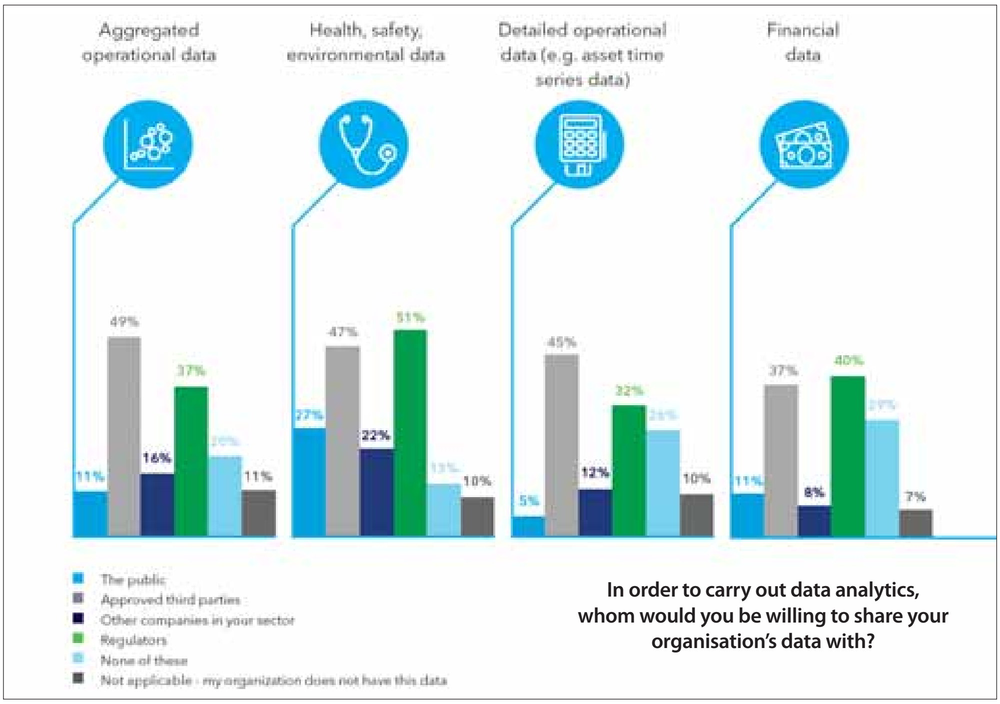


Figure 2. Organisations are more willing to share certain datasets than others, potentially missing out on opportunities to transform business processes

Enabling dynamic and responsive solar assets

As indicated in the DNV GL Energy Transition Outlook (ETO), we forecast that solar will account for 40% of all electricity generation by 2050. This will fundamentally require a digital transformation in and of itself, due to the massive change in grid dynamics that will accompany this change in generation mix from traditional generation capacity to variable renewables of solar and wind, with hydro and more flexible thermal generation. Energy storage and demand response will help to balance load with more variable generation profiles thereby enabling solar and wind to thrive. However, in this future scenario, coordination and forecasting will be paramount. Two way, low latency communication will be required to enable a majority of the electricity from solar and wind, which is addressed through generation forecasting, solar/wind plant design, and responsive inverter capabilities.

Energy storage is already taking hold as a low-cost alternative to deploying peaker plants in some parts of the world, with an increasing number of solar+storage plants making their way as well. Solar+storage assets help to mitigate short-term uncertainty in generation profiles, however they must have clear indications from the IoT on the system itself as well as grid and market indicators to make decisions on operation; when to charge and discharge based on the forecasted energy and market conditions.

The distributed nature of solar in particular, leads to systems ranging from hundreds of megawatts to just a few kilowatts in utility and residential systems, respectively. As such, digitalisation is paramount for coordination across systems and grids, toward enabling a dynamic, integrated system that will operate with increased resilience as variable renewables continue to increase their presence on grids across the globe.

One of the single largest barriers facing the renewable ecosystem and addressing our climate crisis lies in accessing the substantial amount of capital required to deploy this much new renewable capacity. Improving the transparency and integration of system design, construction and operation will lower the financial risk to capital providers, lower the barrier to new providers, lower costs to all energy consumers, and allow solar assets to be built more rapidly to keep up with the energy transition and help meet our building climate crisis.

Furthermore, machine learning algorithms will leverage these large datasets in order to benchmark asset performance across large numbers of diverse assets. Understanding performance and reliability across the diverse landscape of PV system components and designs from hundreds of suppliers, installers and sponsors remains a challenge that will offer myriad insights and lower technology and system performance risks in the future.

Additional areas of opportunity for digitalisation include: mobile connectivity for field workflows to automate data collection on mobile and table devices, integration and communication of digital tools through APIs, the development of digital twins for remaining-life calculations and reliability forecasts, and platform businesses that enable data sharing between asset owners, operators and investors.

Barriers to digital transformation – data and security

With vast amounts of data now widely available, new investment efforts to gather this data are no longer a priority. Our research indicates that the energy industry believes it has the necessary data to enable digitalisation, with only three in 10 respondents considering data gathering as a higher priority. However, two-thirds of the respondents cite extracting value from the data they hold as a high priority.

Collaboration is a key success factor for digital transformation, but our research suggests the energy industry is currently being held back by data security concerns with data sharing considered as unappealing for most respondents and just one in 10 saying they would be willing to share their organisation's data in the public domain. The exception to this is for 'health, safety, environmental data'.

In preventing data sharing, the energy industry restricts access to new market entrants who may bring transformative solutions to add value to the existing data. The barriers decrease when it comes to sharing data with approved third parties and regulators, with around half of participants saying that they would be willing to share aggregated operational data with third parties and 37% with regulators.

If we want to enhance the speed of digitalisation and encourage adoption of new technologies, we need to cultivate honest conversation in the industry. As an industry, we need to be open to sharing not only our data but also our experiences, successes and challenges for the common benefit of the energy industry and the public, which relies on our services.

Data and analytics will be the foundation of solar integration and scale. Understanding how data interacts beyond our physical models is paramount for leveraging massive operational and financial datasets in order to continue driving down the cost, increasing the value and increasing the deployment of solar assets. However, we will not fully realise the benefits of the digital transformation if the data is compartmentalised in a way that prevents one from identifying relationships and leveraging these toward continued efficiency improvements in development, operation and financing. Data security must be paramount. Data must be protected through trusted methods to ensure cyber-security and secure communication protocols. This is an area that must be addressed to ensure data stewards are enabled to share data efficiently.

A key challenge with digital transformation is keeping pace with technological change and user adoption rates. Technology uncertainty was called out as a specific concern within the solar industry. Standardisation across methodologies and technologies is observed as a particular barrier given the rapid development of products and technologies.

People and digital skills

The overall industry responded that a lack of digital skills and lack of digital mindset are the main barriers to digitalisation. Our research shows unanimous recognition that digital skills training is needed, with 91% of participants regarding it fundamental for their organisation to invest in digital skills training, and 71% considering this important for immediate investment.

While this is the case for some respondents in solar, only 13% of those in the solar industry ranked this as their number one concern. Perhaps this could be attributed to the average age of the solar industry workforce. In contrast to the energy industry as a whole, the survey established that the group sampled had more people in the 19-37 age-group bracket than any other industry. It is possible that as solar is a relatively young industry, many in solar may have the required skillsets to better take advantage of digitalisation.

When questioned about the skillsets that were required or lacking within their organisations, 71% of respondents said that they need more employees with combined domain and digital expertise, with 18% claiming to not have any employees with this combined skillset currently. Creativity was also ranked highly, with 65% of respondents saying that they need employees with creative problem-solving skills among their workforce.

We also explored the digital skillsets considered the most important for the energy industry to have among its workforce. Data science came out on top followed by big data analytics, at 41% and 35% respectively. Even though data science was cited as the most sought-after skill, currently only 23% of respondents stated that the role of data scientist exists within their organisation.

Uncertainty in new solar technologies stood out as clear barriers compared to the industry as a whole, with 35% of the respondents citing this as a barrier to digitalisation. This finding was unsurprising. In an industry moving as rapidly as solar, a range of new digital technologies is still unproven. The industry will need to continue to work hard to create compelling use cases that demonstrate the impact of implementing new technology and prove its viability.

Similarly, a lack of industry standards was of higher concern than the energy industry average. Although the solar industry is making attempts at standardisation, it is not as advanced as other industries. Defining a framework based on digital tools will ensure the industry can grow to the next level with the transparency needed to enable rapid growth.

Looking to the future

A key challenge for digital transformation is keeping pace with technological change and user adoption rates. Our research indicates that certain technologies, which for many years were considered emerging, are now seen as mainstream, for example cloud computing and machine learning that will help derive additional value from rich operational datasets. Drone and aerial imaging and analysis are already beginning to reduce the cost of siting, contraction and operation. Newer technologies such as blockchain, augmented reality and virtual reality are still in their infancy and are not currently having a significant impact within the organisations of our respondents.

As the solar industry strives to reduce costs and do more with less, successful digital transformation will be critical to offering innovation that improves efficiency and thereby maximising performance and financial yield. Finally, the relationships across datasets will inform bankability, reduce performance risk and thereby increase revenue for solar assets.

The transformative effects of digital technology are clear. However, digital transformation of the energy industry is not simply applying technology and leveraging big data. To realise the true value of digital transformation, we need to recruit and train employees so that they are prepared with the right attitude, skills and mindset to embrace the opportunity that digitalisation affords the solar industry. ■

This report is based on a global survey of 1,919 energy industry professionals, conducted by Foresight Factory in December 2018 and January 2019. The respondents represent a range of business sizes from start-ups to large corporates and a range of functions within the industry, from board-level executives to senior engineers, developers and financiers.

Author

As global segment leader, solar energy at DNV GL, Dana Olson is responsible for solar innovation and technology development activities to address the evolving needs of the solar industry. Before joining DNV GL, he was a technology manager at the U.S. Department of Energy Solar Energy Technologies Office, where he managed and led programmes and consortia focused on PV module technologies, testing and reliability. Prior to this he was a senior scientist at the National Renewable Energy Laboratory, leading efforts on new materials and designs for PV technologies. He served as an intelligence community fellow during his postdoctoral appointment at Sandia National Labs. He completed his Ph.D. at the Colorado School of Mines in materials science.

Growth of US merchant solar primed to accelerate in near term

Merchant solar | In the US and a number of other major solar markets, merchant solar projects are emerging to fill the gap left by declining subsidies. Jay Bartlett of Resources for the Future looks at the risks and opportunities for merchant PV as it finds its feet

Credit: First Solar

First Solar's Barilla plant was one of the first large merchant PV projects

In the United States, solar installations are expected to surge over the next five years, and particularly so for utility-scale projects. The primary driver of this growth is the stepwise decline of the investment tax credit (ITC) from the current level of 30% to a permanent 10% subsidy. Although the first reduction occurs at the end of this year (to 26%), ITC eligibility is based on the start of construction, so long as projects are placed in service by the end of 2023. With the generous incentive available for this period, merchant solar projects—those that are neither owned by a utility or customer nor with a long-term contract for their power—are an appealing option for new solar capacity in the US.

Tax credit deadline spurs rising installations

Figure 1 shows the expected rise in US utility-scale solar installations, from less than 5GW (AC) in 2018 to over 11GW (AC) in 2023, with a steep decline immediately thereafter. To some extent, this pattern has occurred previously. The ITC had been anticipated to decrease after 2016 (although it was extended), which caused a jump in 2016 installations and a reduction in subsequent years' installations as solar projects were pulled forward to meet the scheduled deadline. However, there is a significant difference between solar projects completed in 2016 and those expected over the next five years. Whereas 56% of all 2016 solar installations (utility, commercial and residential projects combined) were used to meet state Renewable Portfolio Standards (RPS), the percentage fell to 38% in 2017 as solar and wind power generation outpaced RPS requirements [1]. Although certain states have increased their RPS commitments over the past year, a large majority of near-term solar capacity will be likely built without RPS support.

Utility contracts have been prevailing structure

Despite the reduced demand to meet RPS mandates, contracts with utilities remain the most common structure for large solar projects. From Figure 2, utility contracts accounted for 85% and 65% of utility-scale solar capacity added in 2016 and 2017, respectively. Not all of these utilities have mandates for solar or renewable power—they may be in states without an RPS or may have already exceeded their RPS requirements. Utility contracts are also known as physical power purchase

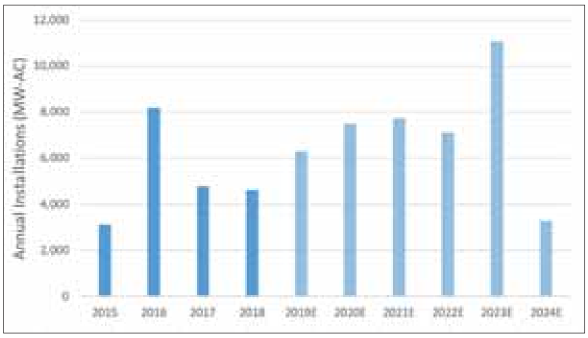


Figure 1. Historical and projected US installations of utility-scale solar. Data for 2015-2022 from [2] Feldman and Margolis 2019, derated by 25% to convert from DC to AC. Data for 2023 and 2024 from [3]

agreements (physical PPAs), so-named because they involve a physical transfer of electricity. Another option for utilities to procure solar power is to own the project themselves, but ownership may or be less advantageous than a physical PPA (due to treatment of the ITC for utilities) and may not be permitted in deregulated markets.

Among the other structural options for megawatt-scale solar, customer ownership and virtual net metering account for minimal capacity. Community solar is a small but growing segment, providing the benefits of rooftop solar for customers in multi-unit housing or without suitable roof space. The final two categories, merchant and customer contracts, together represent the merchant structures for solar. Merchant solar represented 7% and 16% of utility-scale solar installations in 2016 and 2017, predominantly consisting of solar projects that have hedge contracts with large corporations. While the rise in merchant capacity in 2017 is meaningful, merchant solar trails merchant wind by a large margin; nearly half of wind capacity installed in 2017 was on a merchant basis [4]. Moreover, merchant solar in the US has largely been limited to a single structure, a synthetic PPA, whereas merchant wind projects have been completed using a range of structures.

Conditions supporting merchant solar

Despite the comparative immaturity of merchant solar, there are several reasons to believe that the segment will grow substantially in the coming years. As discussed earlier, solar projects will be able to claim the full 30% ITC as long as they start construction by the end of this year and are placed in service before 2024. The 30% ITC was extended in 2015, so developers have had a relatively long time for project planning. Additionally, wind project developers, financiers, and hedging counterparties have completed merchant deals since the early 2000s. While wind and solar have different operational and financial characteristics, the number of successful merchant wind projects and years of experience have likely made market participants more comfortable with the prospect of merchant solar.

Recent trends and developments also favour merchant solar. Historically, wind had a cost advantage over solar, but with the cost of solar power declining by nearly 90% since 2009, average unsubsidised wind and solar costs are now equal [6]. Although recent tariffs on most imported solar cells and modules have raised US module prices above global prices, current US module prices are still lower than ever before. Wind had also benefitted from a more generous incentive than solar, receiving a production tax credit (PTC) of US$23/MWh over 10 years. However, the PTC began phasing out for wind projects starting construction in 2017, and it will expire completely for projects that start construction next year. Similar to the ITC, wind developers have four years from commencing construction to placing projects in service for PTC eligibility, so financiers and hedge providers may turn their attention to merchant solar as the current surge of wind projects subsides.

In considering merchant solar, it is useful first to review the characteristics of a physical PPA, which highlight the contrasting elements of merchant projects. Under a physical PPA, the project receives a fixed price from the utility off-taker for each megawatt-hour of electricity it produces. The utility offtaker typically purchases the electricity at the project's node (where it interconnects to the grid) and assumes responsibility for transmission to where the power is needed. Further minimising risk to the project, physical PPAs have historically been of long duration (often 20 or more years), and utilities generally pose a low risk of default on their contracts. For the project, the low risk comes at a cost—the generation-weighted average levelized PPA price was just US$41/MWh for PV contracts signed in 2017, down from approximately $130/MWh in 2010 [7].

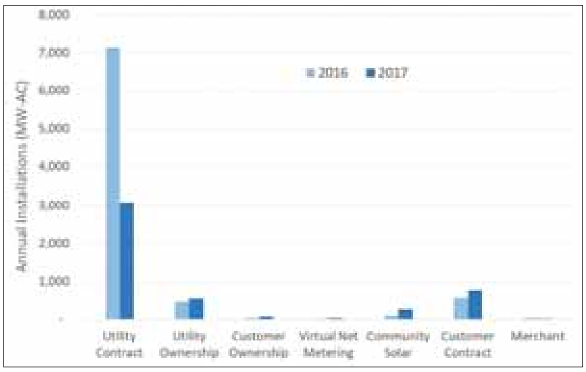


Figure 2. Annual US utility-scale solar installations by sales structure [5]. Solar installations with customer contracts are mostly projects with synthetic power purchase agreements. Data include installations of 1MW (AC) or greater

Risks to merchant solar and international experience

The appeal of merchant solar is thus the possibility of obtaining higher prices by selling into a wholesale electricity market. However, the price risks of doing so are substantial. First, regional wholesale power prices fluctuate, and they may decline significantly during the life of the project. Second, merchant projects receive the wholesale power price at the project's node rather than at the regional trading hub. Depending on congestion in the transmission grid, nodal prices may be considerably less than hub prices, causing merchant plants to lose value on their generation. The earliest large merchant solar plant in the US presents a cautionary tale of price risks. First Solar installed the 18MW (AC) Barilla Solar Project in Texas in 2014 on a merchant basis; it wrote down the value of the project in 2017 due to lower wholesale electricity prices.

Experience outside the US also illustrates the risks inherent in merchant solar. With an exceptional solar resource and robust power demand from mining operations, northern Chile was the first market to host a sizable capacity of merchant solar plants. As of May 2018, Chile accounted for 11 of the largest 15 merchant solar plants worldwide [8]. However, the boom of solar projects constructed between 2013 and 2016, combined with constraints in the national transmission grid, depressed midday electricity prices in northern Chile. As a result, development of merchant solar in Chile stalled in 2017. More recently, Australia has rapidly emerged as a large market for merchant solar, with developers seeking better returns than would be possible given the depressed PPA prices. As of mid-2019, there are an estimated 12 fully merchant projects under development or construction in Australia [9], including such large plants as the 132MW (DC) Merredin, 130MW (DC) Aramara, and the 128MW (DC) Cunderdin solar projects. The simultaneous development of numerous solar projects, including merchant as well as contracted plants, will likely lead to price erosion and transmission bottlenecks. Due to grid congestion, the Australian Energy Market Operator has already cut the percentage of solar output that may receive revenue.

Project finance compels hedging

A critical factor affecting the choice between a physical PPA and a merchant structure is the financing of the project. In the US, utility-scale solar projects are typically financed with three forms of capital: sponsor equity, tax equity and debt. Sponsor equity is often contributed by the project developer, and while it carries the greatest tolerance for risk, it

Contract or Hedging Structure	Quantity Risks			Price Risks	
	Operational & Curtailment	Solar Irradiance	Contracted Volume and Shape	Electricity Hub Price	Basis (Node vs. Hub Price)
Physical PPA (Node)	Part	Part	None	None	None
Synthetic PPA (Hub)	Part	Part	None	None	Full
Bank Hedge (Hub)	Full	Full	Full	None	Full
Proxy Revenue Swap (Hub)	Full	None	None	None	Full
Unhedged Merchant	Part	Part	None	Full	Full

Table 1: Project risk exposures under different contract and hedging structures

also represents a small proportion of the total funding, around 25% [10]. Tax equity, providing roughly 35% of total capital, is designed to optimally utilise the tax benefits of the project, including the ITC, accelerated depreciation and interest deductions. Finally, debt supplies about 40% of the financing, and its low cost requires very low risk to the interest and principal payments it receives. The cost and availability of the project's financing is thus dependent on the structure of its electricity sales. Given the price risks of wholesale power, it would be challenging for a merchant solar project to secure tax equity financing, and even more challenging to attract a lender. Consequently, to obtain both low-cost project financing and a greater expected return than with a physical PPA, the project developer must hedge some of its merchant revenue risk.

Hedging options

Figure 3 illustrates the three prevailing hedging structures for merchant wind projects, all of which are now used by merchant solar projects either in operation or under development. A synthetic PPA (also referred to as a virtual PPA or a corporate PPA) is the only type of hedge already in use among operational US solar projects, likely so because it approximates the features of a physical PPA. Similar to a physical PPA, the project receives a fixed price per MWh of energy it generates. However, the arrangement is solely a financial one—electricity produced by the project is sold into the wholesale market. The project receives the floating price from the wholesale market and pays the floating price to the hedging counterparty, a non-utility corporation. The primary financial difference between a synthetic and physical PPA is if the synthetic PPA settles at a trading hub rather than at the project's node. A hub-settled synthetic PPA leaves the project with so-called basis risk, the difference between the nodal price it receives and the hub price it must pay. If there is congestion in the grid, this price difference may be significant.

The second structure is a bank hedge, which has been utilised by US wind projects for over a decade. While there had been interest in solar bank hedges for several years, only in the past year had solar projects been able to secure these hedges. One challenge with a bank hedge is its transaction cost, which requires greater project size to be sensible. Two solar projects currently in development with bank hedges, the Misae and Holstein plants, are both 200MW (AC) or greater, which is common for wind projects but particularly large for utility-scale solar (only three US solar projects over 100MW were installed in 2017). A bank hedge is also riskier for the project (compared to a synthetic PPA) since it entails a fixed quantity of electricity rather than the variable quantity that the project generates. As listed in Table 1, the structure of a bank hedge exposes the project to quantity risks beyond those that exist in a physical PPA. Quantity risks include the potential for underperformance and curtailment, lower-than-expected solar irradiance, and a mismatch between the timing of contracted volume and actual generation (though this is a lesser concern for solar than for wind). Since all bank hedges settle at trading hubs, basis risk is also a concern for projects using this structure.

Thirdly, the proxy revenue swap is a recently developed hedge, first used by a wind project in 2016. Rather than hedging only against price risk, the proxy revenue swap also insures against weather risk. The project pays the counterparty a percentage of "proxy revenue", equal to the amount the project would earn based on actual solar irradiance levels and hub prices. In return, the counterparty pays the project a fixed annual sum. The project thus fully bears operational and curtailment risk, as well as basis risk, but the project is not liable for lower-than-expected solar irradiance. Proxy revenue swaps require a sophisticated weather risk investor, such as an insurance company, and are uncommon even for wind plants—only four projects have been completed to date. While no US solar project has yet to announce this structure, two Australian projects with proxy revenue swaps, the 95MW (DC) Susan River and 75MW (DC) Childers solar farms, are scheduled for completion this year.

Besides these three hedges, another strategy is to structure the project with partially contracted revenues and partially merchant revenues. The split between the physical PPA and merchant portions can be based on quantity, time, or both. For instance, the 250MW (AC) Phoebe solar project in Texas has a 12-year PPA for 89% of the power. Therefore, the project has 11% merchant exposure for the first 12 years and 100% merchant exposure thereafter. With an approximately 30-year expected life for utility-scale solar, a "merchant tail" after the physical PPA ends has generally been a component of solar projects. The recent change is that potential PPA durations have shortened dramatically (to as brief as seven years), so the merchant tail now accounts for a sizeable proportion of project value. In choosing the split between physical PPA and merchant revenues, project developers may contract for sufficient revenue to satisfy their risk-averse lenders and seek merchant upside for the remainder.

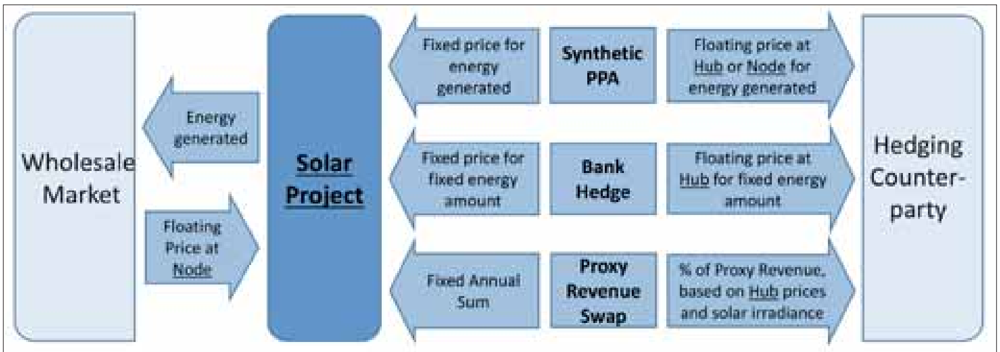


Figure 3. Financial flows from the three hedge structures for merchant solar

Future developments for merchant solar

In the near term, the most significant event for solar will be the reduction of the ITC to 10% for projects installed after 2023. Unless the ITC is extended at a higher level, the percentage of project value coming from subsidies will decline, which will elevate the importance of electricity sales to project financing. This shift will likely lead to less risky revenue structures, either a greater proportion of contracted revenue or the use of hedges, such as synthetic PPAs and proxy revenue swaps, that entail less risk.

Beyond the reduction in subsidies, merchant solar will be challenged by the drop in midday wholesale power prices as the amount of solar generation increases. In such leading markets as California, the erosion in solar prices is already substantial. From 2012 to 2017, solar generation-weighted wholesale power prices fell by 34%, and prices declined further in the first half of 2018 [7]. This price dynamic presents formidable downside and uncertainty to merchant solar projects and hedging counterparties, given the 10- to 12-year duration of many hedges and 30-year duration of solar plants. Battery storage can mitigate this price risk, and US solar PPAs have increasingly included storage, with 16 signed contracts in 2018 versus just four in 2017. Considering the decline in battery prices and rising risk of midday power price erosion, future merchant solar projects may decide to do the same.

Turn to p.70 for further insights into the latest trends in corporate PPAs

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Corporate PPAs as a solution

Business and finance | Complexity, pricing and regulatory hurdles remain key obstacles for the corporate PPA market to overcome. But as Andrew Hedges, Caileen Kateri Gamache and Lee Donovan of Norton Rose Fulbright write, ongoing procurement innovations and new players entering the market suggest this will be a crucial route market for solar for some time to come

Credit: Apple

Tech companies such as Apple have been early movers on corporate PPA market, but new players are entering the market

The issue?

At its launch at Climate Week NYC 2014 the RE100, a global corporate leadership initiative that brings together influential businesses committed to 100% renewable electricity, counted 13 companies as members, alongside NGOs and clean energy experts. As of August 2019, RE100 boasts 191 companies that have made the commitment to go 100% renewable.

Around the world, influential companies are continuing to join RE100 and other initiatives with similar ambitious goals. Although there are undoubtedly laudable intentions backing this trend, the corporate bottom line increasingly demands it. As school children worldwide take part in climate strikes, climate change lawsuits wind through courts and activist shareholders score major climate and sustainability-related victories, companies of all sizes are finding that the sustainability sections of their websites and annual reports require renewed attention. Corporates are realising the reputational benefits of "going green", stakeholders and the public have become more educated on climate and sustainability issues and accusations of greenwashing (companies making environmental claims that are unsubstantiated and/or misleading) and calls for additionality (renewable energy generation that is truly new) have increased around the world.

The solution?

Corporates have a variety of options to meet their individual climate and sustainability policies, including adopting efficiency measures, imposing sustainability measures on supply chains and service providers, utilising green electricity supply tariffs and purchasing renewable energy certificate purchases. Corporate power purchase agreements (PPAs), however, are emerging as one of the most popular solutions.

For developers of renewable projects, this is all well timed. For many, the past five to 10 years have been bumpy ones, particularly developers that base their projects on more established technologies such as solar PV. In regions such as Europe, generous government subsidy schemes have been reduced or removed, often at short notice and sometimes with retroactive effect. In the US, developers face the step-down and eventual phase-out of valuable tax incentives. Moreover, traditional utility PPA opportunities in the US decline as utilities focus more on asset ownership to increase internal capital costs and associated rates of return.

The absence of long-term revenue certainty, coupled with increased power market volatility (often caused by the increase in intermittent renewable technologies on grid systems), makes project development more difficult. This is particularly true for projects that rely on non-recourse project financing. Developers still require a route to market for their projects in order to develop and construct new renewable assets. However, the rapidly growing corporate focus on renewable energy procurement along with the dramatic reductions in renewable technology costs create favourable conditions for continued build-out of projects.

Developers seeking to fill the gap left by government subsidies and dearth of utility off-take opportunities are excited about the relatively new corporate PPA market. Developers in markets where government subsidies have been eroded or removed are looking to corporate PPAs to act as a route to market for projects that do not benefit from tax credits, green certificates or other price stabilisation mechanisms that help mitigate exposure to merchant risk.

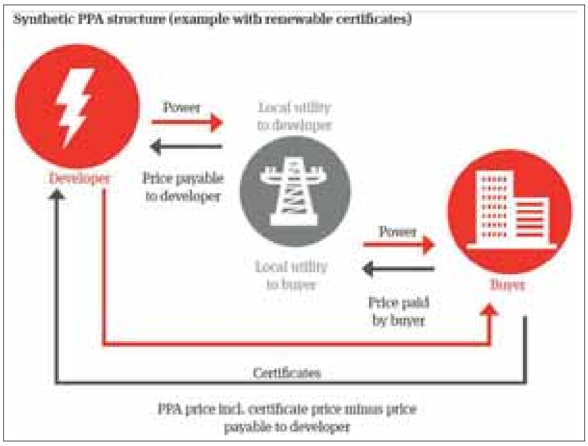

Figure 1. The structure of a typical synthetic PPA [1]

How?

The term "corporate PPAs" has become an industry buzzword the past few years, with varied use and understanding. The term has been used to describe a variety of contracting structures, some of which are quite far removed from a direct power purchase agreement between a renewable project and a corporate buyer. In general, corporate PPAs can be broadly broken down into two types: synthetic/virtual PPAs and sleeved or physical PPAs.

A "synthetic" or "virtual" corporate PPA is a financial derivative. In the most common virtual PPA arrangement, the parties agree to a strike price, with payment flows being determined by comparing that strike price against a market reference price. This contractual arrangement does not involve the physical delivery of output to the buyer or an agent appointed by the buyer (for example a utility). These types of corporate PPAs may be structured in various ways. For example, they may be two way or one way. In the former, where the market reference price is higher than the strike price, the generator pays the difference to the buyer. Where the market reference price is lower, the buyer pays the difference to the generator. The volume contracted under the agreement can also be specified in a variety of ways and need not be tied completely to the actual generation of the project. This type of virtual PPA is generally known as a "contract for difference". As the market becomes more comfortable with contracts for difference, we are seeing unique additions and modifications, including shared upsides or downsides to split the risk of particularly high windfalls on either side, the introduction of temporal risks by making settlements based on day-ahead pricing irrespective of whether the project clears in day-ahead or in real-time markets, and other creative mechanisms to define and predict the value of the contract.

It is important to note there is typically one physical aspect in a synthetic PPA. For example, in the US and other parts of the world, the transaction typically involves green certificates (as in the diagram in Figure 1). The corporate buyer will usually require the green certificates associated with the energy output of the project be delivered to the buyer or retired in the buyer's name. The transfer of certificates, evidenced via attestations or formal clearinghouses

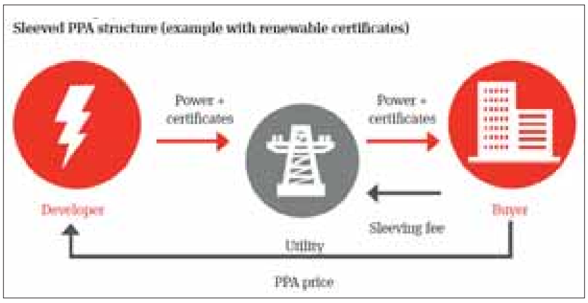

Figure 2. The typically structure of a sleeved PPA [1]

that track environmental attributes, is the primary means of demonstrating a corporate obtained "green" energy in the US. If electricity is sold without all associated environmental attributes, it is often described as "brown" energy and is of little to no value to corporates. The renewable energy certificates are used by the corporates to offset their overall electricity usage. In this manner, a corporate is able to offer tangible evidence of its performance against its corporate mandate or other commitments. Some transactions take a different approach. For example, in markets such as those in the Nordics where there is already a high deployment of low carbon generation on the system and an established secondary market for green certificates, the corporate buyer may separately purchase green certificates in the market and allow the project to sell the green certificates associated with its power output separately.

"Data gathered by industry observers demonstrate a marked growth in the cumulative volume of corporate PPAs being signed at both a global and regional level, from 2.3GW in 2014 to 13.5GW signed contracts in 2018"

A "sleeved" or "physical" PPA often (but not always) involves a direct PPA between the corporate buyer and the generator. The corporate buyer usually enters into associated arrangements (either managed by the corporate buyer itself or via a utility) to enable the output purchased to be used for the benefit of the corporate's wider facility load.

Under this approach, the corporate buyer enters into a PPA with the generator. The corporate buyer simultaneously enters into a PPA with its incumbent energy supplier. This second PPA requires the utility to act as the buyer's agent in managing the off-take of power from the generation facility. Generally the design of the linked PPAs is intended to mitigate risk for the corporate buyer by passing through obligations and liabilities to the extent possible. Usually the corporate buyer will agree with the utility how the intermittent electricity output of the generation facility will be credited against the corporate's electricity requirements. This will generally involve management fees associated with the intermittent nature of that generation output.

In the US, there are various state regulations that govern the structure of a physical PPA and, in some places, prohibit them. A structure adopted by many US states that solar developers and large commercial and industrial off-takers have embraced is "net metering." Under this arrangement, the developer will install the generating system behind the meter on the host customer's facility (e.g., on parking garages, rooftops, adjacent land). The PPA between the parties requires the host customer to consume all of the electricity it can from the project, and any excess energy flows to the grid. State laws typically limit the size of the generating unit to ensure the host customer still consumes more electricity from the grid than is sent onto the grid from the on-site system. Corporates with large warehouses and stores have spurred this trend and been influential in shaping local laws to accommodate these physical PPA arrangements.

A bright future…

As noted above, the growing focus of corporates of all sizes on sustainability presents a clear opportunity for large-scale deployment of corporate PPAs globally. Data gathered by industry observers such as Bloomberg New Energy Finance demonstrate a marked growth in the cumulative volume of corporate PPAs being signed at both a global and regional level, from 2.3GW of signed contracts in 2014, the year of the formation of RE100, to 13.5GW signed contracts in 2018. Corporate PPAs are not new instruments and some of the early-mover corporates are now established market players with portfolios of multi-technology corporate PPAs across different jurisdictions. That experience (both positive and negative) is leading to continued innovation in the market, with a number of experienced buyers using competitive procurement processes to push for more innovative contracting structures and risk mitigations.

In addition to increased cumulative volumes of signed corporate PPAs, we are seeing new corporate entities entering the market. Given the complexities of a corporate PPA, an "education" process is often required. The extra time developers take to assist with this process often pays off in repeat transactions once the corporate becomes comfortable. Once a corporate has signed its first contract, efficiencies can be utilised going forward in the same market and in other jurisdictions (subject to mandatory local law requirements). It is not uncommon in the US to see developers repeatedly working with the same corporates and lenders, which reduces costs and resources for all parties. There are also smaller corporates looking at corporate PPA solutions either individually or as part of aggregated corporate PPA structures. Developing efficient contractual and technical tools to allow a significantly greater number of smaller buyers to be involved in corporate PPAs is one of the key near-term challenges for the sector. As developers and off-takers become more sophisticated, we will likely see corporate PPA structures evolve. The goal for the future will be to continue to find ways to increase the value for all participants.

…albeit, with a few challenges

One of the biggest challenges for corporate PPA deployment to date has been regulatory hurdles. Although at a very basic level a corporate PPA is a simple supply contract (and in the case of synthetic or virtual PPAs may not even require delivery of any goods), the regulated nature of the electricity industry adds great complexity. In the US, there is the potential for both federal and state regulators with competing priorities to regulate physical energy sales. A synthetic PPA is likely to be treated as derivative product in many jurisdictions, requiring consideration of financial services regulations. The US Commodities Futures Exchange Commission regulates virtual PPAs in the US under a relatively new regulatory structure that many developers and corporates are still learning, for example. These types of regulations are foreign to other jurisdictions and the popularity of corporate PPAs may outpace the capacity of some regimes to accommodate their use. Early participants in these markets will have certain advantages in helping to shape the regulatory regime and corporate PPA structure. On the flip side, their experience will also be the basis for the future "lessons learned" in such markets.

In addition, corporate PPAs require interaction with the operational and/or construction contracting framework and while a corporate PPA that applies to an operational asset only is more straightforward, the signing of a corporate PPA in the pre-construction phase may be a requirement for a corporate in order to tick the "additionality" box of its own internal sustainability policies. Although a degree of standardisation has been achieved by market leaders in certain regions, key differences in electricity markets mean that a template for example in the US looks very different to, say, a template form in Northern Europe. In Europe, the European Federation of Energy Traders (EFET) has been working with developers, corporates, advisors and financiers in order to produce an EFET standard corporate PPA. A review of the first draft shows that, in order to cater for the various types of corporate PPA that parties may consider using, the document has a great degree of optionality and at first glance can look overbearing. It will be interesting to see if the EFET form of corporate PPA can operate like the other forms of EFET documents or if, given the nature of the contract, it will need to evolve to be more like the forms of construction contract that renewable developers will be familiar with (FIDIC, JCT, NEC, etc.). The experience in the US to date has demonstrated that it is very challenging to find parties willing to execute a "standard" contract without some degree of negotiation and legal review. This, in turn, drives up costs and makes the economics of smaller corporate PPAs difficult. It is an issue some in the US market are actively working to overcome.

> "Developing efficient contractual and technical tools to allow a significantly greater number of smaller buyers to be involved in corporate PPAs is one of the key near-term challenges for the sector. As developers and off-takers become more sophisticated, we will likely see corporate PPA structures evolve"

There are also a variety of competing avenues to achieve corporate climate and sustainability goals. Many of the other products in the market, such as green supply tariffs, purchase of green certificates, etc. are often simpler and quicker to put in place. An energy procurement manager in a corporate may not be willing or able to engage in the time and complexity of a corporate PPA, particularly a smaller organisation where energy procurement may be just a small part of his or her role. In addition, the tenure of corporate PPAs that are sought by developers (10-15 years) are often much longer than the usual mandate that a procurement manager may have for long-term contracts (for example five to seven years).

There are numerous risks to consider before entering into a corporate PPA. These include factors such as: market risk, price and project revenue risk, tenor risk, currency (or foreign exchange) risk, credit risk, scheduling risk, basis risk, balancing risk, volume risk, shape or profile risk, construction risk, performance or operational risk, change in law risk and force majeure risk. These risks require allocation between the parties in the corporate PPA and, where appropriate the use of contractual or physical mitigation tools. As corporate PPAs have evolved to offer innovative products such as baseload volumes, so too have the mitigation tools such as hedging, proxy revenue swaps, co-location of battery storage, etc. If risk profiles cannot be allocated in the corporate PPA, the introduction of third parties into the contracting framework increases complexity.

While the cumulative numbers of corporate PPAs signed each year are increasing at a rapid rate, a more detailed look at the data shows that growth is focused. A small number of

FINANCIAL, LEGAL, PROFESSIONAL

market players in a handful of jurisdictions make up the bulk of the numbers. While there is opportunity to study "lessons learned" from transactions in the US or Nordics, the nature of different electricity systems and regulatory structures means that contracting frameworks are not readily transferable from one region to another. The growth of the corporate market has introduced new players and while this presents opportunity there is a repeat "education" exercise required. As established market players fulfil their quotas the scope for smaller corporates to join aggregated structures is reduced.

The outlook

The data suggest that the deployment of corporate PPAs will continue to rise. The questions that the industry is concerned with are how fast and where? Established players in established markets continue to provide innovative contracting frameworks and the market is responding with the development of contractual and physical risk mitigation tools. While demand from "big tech" may not continue at the same pace it will not stop completely and there are other corporates, from a variety of industries, who are stepping into the market. New and smaller corporates will require education, given the complex nature of the documents but standardisation exercises and aggregation transactions provide opportunities to speed up this process in an efficient manner.

As mentioned previously, for all the complexity that can be introduced in a corporate PPA arrangement, at its core it is a supply contract for green electricity. Like any supply contract, pricing is key. It is pricing in each region and jurisdiction which will ultimately drive, or hinder, the development of corporate PPAs as routes to market for renewable projects. ■

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Agrophotovoltaics: harvesting the sun for power and potatoes

Applications | The question of whether to use valuable land for farming or solar power generation has been a subject of fierce debate in the green energy transition. But, as Boris Farnung, Maximilian Trommsdorff and Stephan Schindele of Fraunhofer ISE write, the two activities need not be in conflict with each other and, with a new generation of solar technologies, can in fact be mutually beneficial


Credit: Fraunhofer ISE

The pilot agrophotovoltaic system uses bifacial glass-glass modules arranged in rows of two

Agrophotovoltaics: solving the food versus fuel conflict

For farmers in Germany, energy harvesting is economically more beneficial than food production. Thus, for example about 18% of arable land in Germany is used for growing energy crops. And it is true that Germany must allocate new land for the production of solar electricity in order to meet the urgent expansion of renewables needed for the energy transformation. Studies show that photovoltaic installations in the range of 200GWp are required in order to meet the goal of reducing carbon emissions by 85% until 2050. This leads to a significant increase in the competition for land usage – "food versus fuel" – and at the same time presents an ethical dilemma: valuable, arable land is used to produce energy, while at the same time food is being imported from threshold and developing countries. As a result, these countries grow crops for export and less food is available for the indigenous population. But conflicts over land use are also arising in emerging and developing countries, as growing populations and rising living standards require more energy and food production.

Instead of being competitors, photovoltaics and photosynthesis can actually complement each other. So-called agrophotovoltaic (APV) systems make the efficient dual land usage possible: the farmer not only provides potatoes but also electricity – from the same piece of land – which dramatically increases the land use efficiency. The concept is not novel, quite the contrary: it was conceived by the founder of the Fraunhofer Institute for Solar Energy Systems ISE in Freiburg, Prof. Dr. Adolf Goetzberger, and his colleague Dr. Armin Zastrow in a paper published in 1981 [1]. Since then, numerous large agrophotovoltaic (APV) systems have been installed worldwide. Leading countries in the field are France, Japan, China, Korea and the United States, with support schemes for agrophotovoltaics established. The overall installed capacity is estimated to be 2.1GW, with approximately 1.9GW in China alone. Nevertheless, only a few research plants exist, and the full scope of applications is still to be investigated.

Pilot project "Agrophotovoltaics–Resource-Efficient Land Use"

In the project "Agrophotovoltaics: Resource-Efficient Land Use" (March 2015 to June 2019), the technical, societal, ecological and economical aspects of the technology were investigated in a pilot demonstration project. The seven partners of the model project, led by Fraunhofer ISE and financed by the German Federal Ministry of Education and Research and FONA (Research for Sustainable Development), also wanted to clarify the political and energy economical boundary conditions that are required to help the new technology break into the market.

The pilot APV system was installed at the organic Demeter farm in Heggelbach, near Lake Constance. On a test field covering one third of a hectare, 720 bifacial modules with a total power of 194.4 kWp were installed at a height of five meters above the ground. This clearance height makes sure that the use of versatile agricultural machinery is not restricted. The rows of semi-transparent glass-glass modules are placed at a slightly larger distance so that the crops growing underneath receive at least 60% of the total incoming irradiation. Modules are arranged in rows of two, with a gap between the rows to better distribute

Credit: Spinnanker

The foundations were fixed by spinning anchor rods

rainwater. The modules' total surface measures 1206 square meters. The deviation from the south is 52 degrees, with an angle of inclination of 20 degrees.

Within the project, Fraunhofer ISE has developed accurate and validated calculation methods to design the system with a balanced ratio of light and shade. In addition, based on comprehensive light-management simulations, it is ensured that the irradiation is homogeneous over the designated area. Thus, Fraunhofer ISE is uniquely positioned to support project developers to define a system concept optimised for solar power and food production in the same area.

An important technical aspect was the possibility of deconstructing the plant without, for example, leaving foundations in the ground. The foundations were therefore laid using a spinning anchor system: up to eight-meter-long spinning anchor rods were turned down on a cast plate, in the center of which an Alpine anchor was drilled into the ground. In order to avoid damage to the facility by agricultural machineries, the posts were fitted with a ram protection, which was also fastened with anchor rods. In total, about 50 tons of steel were used.

One of the Demeter farmers' demands was that they could carry out their normal crop rotation under the plant: winter wheat, clover grass, celery and potatoes. The aim for the farmers was to achieve at least 80% of the usual yield. In order to be able to prove this, the same crops were cultivated on a reference area directly next to the test field. Over a period of three years, the experts for agricultural research of the University of Hohenheim accompanied the agricultural aspects of the project, from the measurement of the climatic conditions under the plant, through the yield and quality of the products to the effects on biodiversity.

From September 2016 to June 2019, the solar power and the agricultural yield were assessed, accompanied by social science studies on the acceptance by the local population. Two full harvest cycles were completed during the project period.

Agricultural results: high yields in hot and dry summer

Over the first 12 months (October 2016 to October 2017), four crops (winter wheat, potatoes, clover and celery) were grown and harvested.

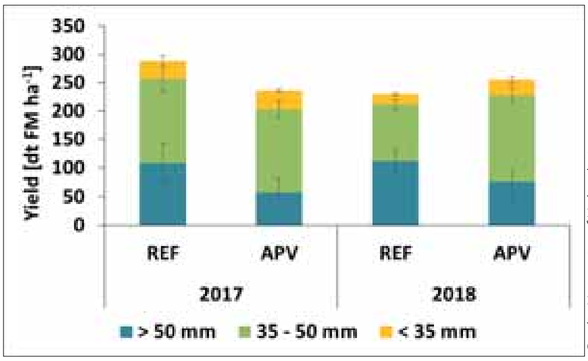
The University of Hohenheim investigated the response of the crops to the local changes in environmental conditions. Data on the microclimatic parameters such as photosynthetic active radiation (PAR), air and ground temperature as well as precipitation were collected. The analyses indicated that the PAR under the APV system is reduced by about 30%. In the first evaluated year, the local air temperatures under the APV system did not differ significantly to the reference plot. Washouts have been observed at single locations in the field, depending on the crop and its stage of development. In particular, the scientists observed a slightly less homogeneous distribution of rain water below the PV panels compared to the reference area.

While the clover yield was reduced only slightly (-5.3%) due to shading from the APV, the yield decrease for potatoes (-18.2%), wheat (-18.7%) and celery (-18.9%) was higher. The winter wheat and the potatoes growing under the PV array showed a slightly slower development than the same crops on the reference plot. At harvest, no mentionable difference in development was observable, so that the crops under the APV and on the reference field could be harvested at the same time. The results from the first year of practice showed that all four crops were qualitatively good and marketable. In comparison to the crops from the reference plot, a lower yield was observed, but it was still within the target horizon determined in advance by the farmers. It has to be noticed that the harvest was a bit too early for some of the plants under the APV array. Normally the potatoes and celery plants should have been given about two more weeks to ripen.

The second year, however, showed a different picture: In 2018, the yields from three of the four crops grown under the APV system were larger than the reference plot. The crop yields for celery profited the most by the system, with a gain of 12% compared to the reference. Winter wheat and potatoes produced a gain of 3 and 11% respectively, and clover a minus of 8%. In addition, in the case of potatoes, the marketable share (35-50 millimeters in size) was larger under the APV plant than under the reference area.

In spring and summer, the soil temperature under the APV system was less than on the reference field; while the air temperature was identical. In the hot, dry summer of 2018, the soil moisture in the wheat crop was higher than on the reference field, while in the winter months, it was less, as for the other crops. The agricultural scientists of the University of Hohenheim assume that the shade under the semi-transparent solar modules enabled the plants to better endure the hot and dry conditions of 2018. In their view, agrophotovoltaics could mitigate climate change effects on agriculture in many regions.

For the research project, no particularly shadow-tolerant or even shade-loving plants were selected, but varieties normally marketed by the Demeter farm. It can be assumed that shade-loving plants such as hops, leafy vegetables, legumes or certain wine and fruit varieties would have shown significantly better yields. Further follow-up research projects are needed to investigate this in more detail.

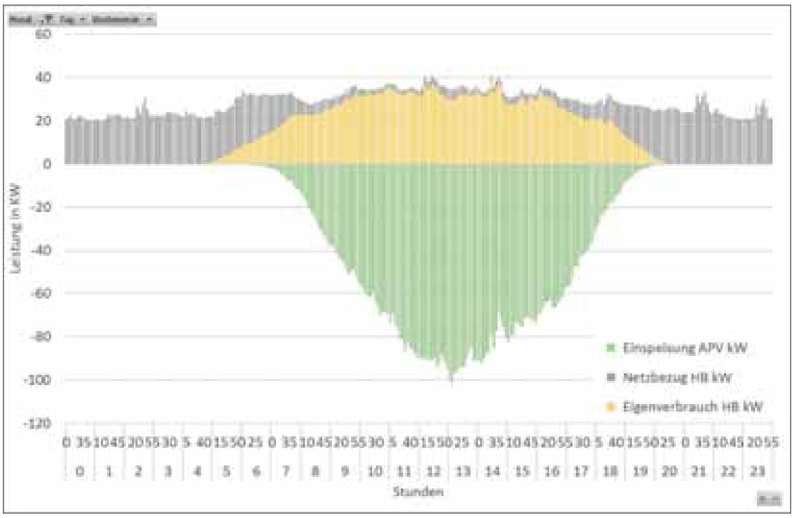


Credit: University of Hohenheim

The marketable share (35-50 mm) of the potato harvest was higher under the APV system.

Solar energy harvest: yields exceed expectations

As for the solar yield, the project results of the first year already exceeded expectations, at least with respect to the initial specifications. In the first 12 months of operation, the PV plant produced 245,666kWh of electricity, or 1,266kWh



Credit: BayWa r.e.

During summer, the APV system covers the electricity load at the farm almost completely. The green area represents the feed-in of the solar power into the grid, the yellow area represents the own consumption, while the purchased power from the grid is plotted in grey

per kWp installed. The power output is mainly influenced by the use of bifacial module technology, but also by a larger distance from row to row which results in lower shading and temperature losses compared to conventional power plants. A detrimental factor with regard to the electrical yield is the orientation of the system, which is 52° off south.

In the second year of operation, the solar irradiation totalled 1,319.7kWh/m^2, an increase of 8.4% compared to the previous year. The energy output of the APV system amounted to 249,857kWh, corresponding to an extraordinarily good specific yield value of 1285.3kWh/kWp.

BayWa r.e. renewable energy GmbH, responsible for the construction and the load management of the APV system, also evaluated the self-consumption at the farm. Over the day, the power produced by the APV system was well matched to the power consumption on the Demeter farm. In the summer months, the load demand was covered almost fully by the APV system and in July close to 100%. The electricity generated could supply the annual demand of 62 four-person households. The Demeter farmers use it primarily for processing their products and charging their electrical vehicle. With the subsequent installation of a 150kWh battery in 2018, the farm community could increase the own consumption rate for the solar power to approximately 70%. This shows that if the electricity is stored and used on site, for example for the use of electric agricultural vehicles, additional sources of income arise due to synergy effects.

While the expected capex costs of an APV plant are about one-third higher than for a conventional open space plant, mostly due to the higher racking system and higher logistics costs, the OPEX costs tend to be about a quarter lower. This is due to synergy effects such as the avoided costs for mowing, surveillance or a fence. The electricity production costs of a typical APV system of 2MWp today are competitive with a small PV rooftop system (<10kWp). Further cost reductions due to economies of scale and learning effects are to be expected.

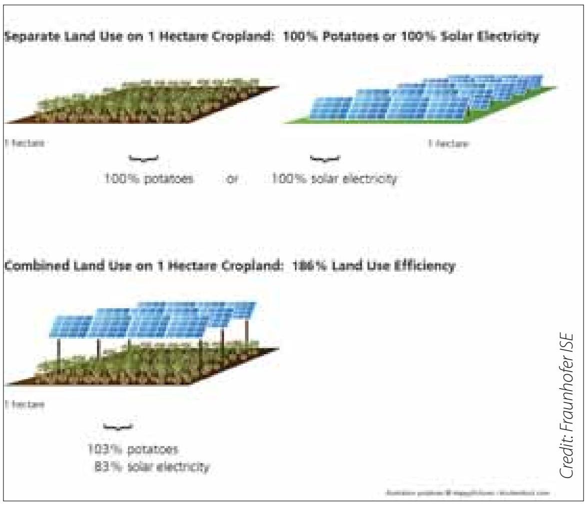
Land use efficiency dramatically increased

The results from 2017 already showed a land use efficiency of 160% compared to a single use of the land (i.e., either agriculture or PV). The performance of the APV system in the very hot and dry summer of 2018 greatly exceeded this value, as the partial shading underneath the photovoltaic modules improved the agricultural yield, and the sun-rich summer increased the solar electricity production. Based on the 2018 potato yield, the land use efficiency rose to 186% per hectare with the APV system.

The APV-RESOLA project examined not only technological and agricultural aspects, but also the acceptance of this new technology by the local population, as this could become an obstacle to higher market penetration ("not in my backyard"). In two citizen workshops, social scientists from the Institute for Technology Assessment and System Analysis (ITAS) of the Karlsruhe Institute of Technology discussed which forms of

> "While the expected capex costs of an APV plant are about one-third higher than for a conventional open space plant, mostly due to the higher racking system and higher logistics costs, the OPEX costs tend to be about a quarter lower"

energy production they would accept in their immediate living environment. One workshop was carried out before the construction of the plant, the second one afterwards, and there was also a survey. The results showed that the acceptance of APV systems increases if local citizens recognize clear advantages for themselves, for example if they are involved financially within the framework of a citizens' energy cooperative. The aesthetics of the plant was a point of criticism, especially with regard to the tourist attractiveness of the region. Still, the citizens surveyed prefer the APV system to a conventional PV plant. They also pointed out that uncontrolled growth and "pseudo-agriculture" must be avoided, i.e. clear standards must be established by the legislator with regard to the definition of an APV system. While in France, Japan, Korea and the USA there are already financial support schemes with corresponding definitions, this is lacking in Germany.



Credit: Fraunhofer ISE

The land use efficiency was dramatically increased during the hot and dry summer of 2018

Further research topics: horizontal and vertical technology development

Now that evidence of increased land use efficiency and economic viability has been provided, further horizontal and vertical technology development is needed to unlock the full potential of agrophotovoltaics. To provide the necessary proof-of-concept before market entry, other techno-economic APV applications must be compared and larger systems in the MW range need to be realised. Different possible applications shall be explored, such as the combination with fruits, berries, hops, wine crops and livestock farming. As far as vegetable cultivation is concerned, there is currently a trend towards closed cultivation. This serves on the one hand to adapt to climate change (protection against extreme weather conditions, improvement of the water balance) and to "green the deserts", but also helps to reduce the use of pesticides, as no pests can penetrate. To give an example, in France there are already large greenhouses with APV. In the future, a combination with organic photovoltaic modules or flexible photovoltaic foils would be conceivable: special absorber layers in the photovoltaic cells would allow certain parts of the sunlight, which are particularly conducive to plant growth, to pass through, while protecting the plants from excessive radiation.

Aquafarming is another possible application: in 2018, Fraunhofer ISE carried out a proof-of-concept study analysing the possibility of installing APV at shrimp farms located in the Vietnamese Mekong Delta. In this densely populated region with an energy consumption growing 10% annually, there is an increasing competition for land between aquaculture and renewable energy. The study showed that solar-aquaculture habitats have the potential to promote the deployment of renewable energy as well as enact measures to counteract climate change, expand shrimp production yet protect water resources, decrease land use and reduce CO2 emissions at the same time. Based on the first analyses, the pilot project in Bac Liêu can save about 15,000 tons of carbon dioxide emissions annually and reduce the water use by 75% compared to a conventional shrimp farm. The aquafarm operators appreciate other advantages from this technology, such as protection of shrimps and fish against predatory animals, improved working conditions due to shading and a stable or lower water temperature that helps to promote the shrimps' growth. The combination of aquaculture and photovoltaics is expected to significantly increase the land use rate.

> "Solar-aquaculture habitats have the potential to promote the deployment of renewable energy as well as enact measures to counteract climate change, expand shrimp production yet protect water resources, decrease land use and reduce CO2 emissions at the same time"

In order to exploit the technology on the vertical level, further development work is required in the areas of organic PV film technologies, energy storage, water treatment, irrigation systems, agricultural robotics, electro-mobility, tracking systems, materials research and structural design. Another aspect to be considered is the rising use of electric vehicles in agriculture, which could increase the own consumption of solar power on farms.

Two years ago, the agricultural machinery manufacturers Fendt and John Deere introduced the first fully electric battery-operated tractors. A future vision is "swarm farming", with automated solar-powered electric farm machines working under the APV array and receiving their power directly from the APV system. Already today, machines exist that autonomously cut weeds or eliminate pests such as the Colorado potato beetle without using chemicals, polluting the ground water or the soil. Thus, farming would become more sustainable not only with environmentally friendly machines but also through intelligent technology.

High potential for arid regions

Another current research focus addresses the transfer of APV technology to other climate zones. The technology of dual use may prove to be especially advantageous in semi-arid threshold and developing countries. The results from the summer of 2018 demonstrate the enormous potential of agrophotovoltaics for arid climate zones. Crops and livestock can benefit from the shade given by the PV modules, while the electricity can be used for seawater desalination, water treatment or irrigation pumps. Fraunhofer ISE is already working on several projects to transfer the technology to threshold and developing countries as well as for new applications. A pilot study that Fraunhofer ISE carried out for the Indian state of Maharashtra showed that shading effects and less evaporation might result in up to 40% higher yields for tomatoes and cotton crops. In certain cases, the experts expect the land use efficiency to almost double for the region. In another project, carried out within the EU Horizon 2020 programme, the Fraunhofer ISE researchers are working together with partners from Algeria to test the effects of APV systems on the water balance. Besides

Credit: Hofgemeinschaft Heggelbach

Using agricultural vehicles under an APV system is not a problem. In the future, these could be e-vehicles

less evaporation and lower temperatures, harvesting the rain water with PV modules also plays a role.

Together with Fraunhofer Chile, Fraunhofer ISE is currently testing three 13kWp APV systems in the Chilean communities of El Monte, Curacavi and Lampa, which are the first of their kind in Latin America. Investigations involve adapting and optimising the APV technology according to the specific climatic and economic conditions in Chile. The results of both the crop and solar power production are very positive. In the arid and semi-arid regions in Northern and Central Chile, there is great potential for APV, since a large percentage of the people live from agriculture, which is impacted by the increasing amount of dry periods, desertification and water scarcity due to climate change. The projects show that the partial shading of crops planted underneath APV can reduce their need for water and also offer livestock shelter from the sun. Also, it is expected that various fruits which normally do not grow well in dry climates with high solar radiation would grow underneath an APV system. The three pilot plants will be monitored for three additional years, operating them as on-field labs. A long-term plan involving different type of crops has been coordinated with the farmers, so it will be possible to test the concept with a large variety of products.

Apart from the higher land use efficiency, APV systems can help to improve the socio-economic situation of rural areas in threshold or developing countries. In those villages often situated far from the grid, the quality of life is increased immensely just with the electric output of a few solar modules providing improved access to information, education, clean water and also better medical care. For example, in sub-Saharan Africa, about 92% of the rural populations have no access to electricity. APV offers new sources of income to the local population and at the same time reduces the dependence on fossil fuels, needed for diesel generators. Besides this, solar power can be used for cooling, processing and preserving agricultural crops, making them more profitable as they can also be marketed outside the harvest period.

Authors

Boris Farnung joined the Fraunhofer Institute for Solar Energy Systems ISE in 2008. He is head of group PV Power Plants and over the years has gained extensive experience in quality assurance, bankability support, testing and characterisation on both the module and the system level from projects worldwide. He is also operating agent of the IEA PVPS Task 13 - Performance and Reliability of Photovoltaic Systems.

Stephan Schindele is working on his doctoral degree about the innovation processes of agrophotovoltaics and their political support. He is project manager of agrophotovoltaics at Fraunhofer ISE.

Maximilian Trommsdorf is a project manager and scientist specialised in agrophotovoltaic systems in the team Applied Storage Systems at Fraunhofer ISE. In 2015, he received his M.Sc. in economics and politics at the University of Freiburg.

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Abu Dhabi to host unrivalled gathering of government, business and finance leaders for the 2020 World Future Energy Summit

Solar Expo & Forum to take centre stage at the World Future Energy Summit from 13-16 January

Abu Dhabi, United Arab Emirates

The World Future Energy Summit will host an unrivalled gathering of top-level government and business leaders when it returns to Abu Dhabi in January 2020, further reinforcing its place as the leading global event and business marketplace for future energy, clean-tech and sustainability.

Hosted by Masdar and part of Abu Dhabi Sustainability Week, the World Future Energy Summit has a strong track record of bringing together the complete range of stakeholders needed to achieve genuine change, including from government, private sector majors and SMEs, technology providers and finance. Visitors and delegates for 2019 included 13 heads of state, around 120 government ministers and 3,000 C-level executives. The main focus of the event is the Solar Expo & Forum, the region's largest solar exhibition, with an extended programme that includes water, waste management and smart cities.

Around US$10.5 billion worth of new business was announced during the 2019 edition, and that figure is expected be higher in 2020 as the Middle East market for renewables continues to experience strong growth.

"The World Future Energy Summit provides the perfect platform that connects government, business and finance to enable the advancement and transfer of ideas, technology and investment to stimulate sustainable development and growth," said Grant Tuchten, Group Event Director.

"The event facilitates the acceleration of sustainable development and innovation. We have the policy makers, the buyers and the vendors of sustainable solutions, the investors and financiers, and innovators bringing new ideas, all coming together in Abu Dhabi."

Held annually, the World Future Energy Summit will include exhibition and forum programmes across five main pillars: energy, solar, water, waste and smart cities.

In the Middle East, with its high levels of solar potential, renewable energy

supply grew by 7.1% or an extra 1.3GW, to reach a total of around 20GW installed capacity, while the GCC states are planning an additional 7GW of new power generation from renewable sources by the early 2020s. The installed capacity of renewable energy in the GCC grew four-fold just in the period from 2014 to 2017, and the region is placing renewable energy – primarily solar – at the centre of economic planning.

In 2019, the World Future Energy Summit attracted more than 800 exhibitors on the show floor, with around 33,500 attendees during the event's four days. More than 80% of visitors have purchasing power within their organisation. As a platform facilitating knowledge-exchange, the World Future Energy Summit hosts industry forums that offer expert-led sessions and networking opportunities at the strategic, commercial and technical levels.

The World Future Energy Summit will be held at Abu Dhabi National Exhibition Centre (ADNEC), from 13 - 16 January, 2020. For more information please visit **www.worldfutureenergysummit.com**

Project construction safety in utility-scale solar

Safety | Construction trades are among the most dangerous, and solar is no exception. Matthew Skidmore of CS Energy explains why safety is paramount for solar project developers, project owners, financiers and EPCs

Construction trades rank in the top 20 most dangerous jobs in the United States [1]. Construction safety on solar project sites is an important underpinning of the project's success for all stakeholders, from solar project developers, project owners, financiers and engineering, procurement and construction firms (EPCs), to the subcontractors and labour force that execute field work. As the solar industry grows and advances, so does attention to the safety of the workers building these immense power generation giants.

A solar EPC company's safety record plays an undeniable role in the success of the company. The gravitas of a strong safety record builds reputations that enable companies to grow and prosper. Having a positive safety record is a qualification factor in many project bidding processes and can open the doors to opportunities not available to lesser ranked competitors. A strong safety record impacts a solar project's bottom line by reducing liabilities and insurance claims which ultimately increases profitability for all stakeholders. It also means a lower experience modification rate (EMR) that translates to a discounted insurance premium. A safety record is an important factor in solar project financing as stakeholders seek to reduce construction risks. A culture of safety enhances the welfare of employees, supports recruitment and contributes to the growth of the organisation.

Accidents and injuries can weigh on companies' track records in addition to workers' compensation claims and lawsuits that can linger long term.

Top five best practices

As safety standards for solar construction evolve to meet industry demands, it is crucial that we establish consistent, sustainable, long-term safety programmes. Here, we share our top five best practices for safety:

Credit for images: CS Energy

1. Make training a top priority

Safety training is our number one priority. A robust training programme with a dedicated budget is worth the investment. That investment is directly related to the success of a company. Ensuring safety means that staff understand and follow company protocols. They have the knowledge to use company resources properly and to execute job directives and activities effectively. Training is also a factor in employee retention. In a recent survey of 10,000 workers conducted by Price Waterhouse Cooper, 35% of those surveyed believe in the value of training and development programmes and consider them an important factor in employment [2].

The first day that employees and subcontractors join CS Energy, they attend a training programme, which includes a site safety orientation and is followed with monthly educational sessions and regular online trainings. Additionally, the team is able to leverage the experience and resources of the safety team, who spend 75% of their time in the field executing trainings and managing safety-related activities.

Safety is as much of a concern on solar project sites as any other construction site

CS Energy continuously improves its training programme through the regular reports that the Safety Department receives. After analysing the data, the Safety Department identifies training gaps and is able to close those gaps by further utilising the various educational channels already in place.

CS Energy also integrates seasoned senior-level managers into every team. As a valuable resource and training asset for team members, the team leaders provide beneficial coaching to all employees. Their knowledge and experience keep projects on track and provide safeguards for lesser experienced staff.

Benefits of a strong safety record

1. Ensures that everyone goes home to their families at the end of the day
2. Supports the growth of the company through employee welfare and enhanced recruitment
3. Opens the door to project bidding opportunities
4. Reduces liabilities and insurance premiums
5. Is a factor in solar project financing

2. Actively support a company culture of safety

To effectively maintain a culture of safety, safety needs to be a top priority of the executive leadership team driven by supportive actions. The Safety Department should report to top level management and safety policies should flow back through the entire organisation. Our executive management team supports the Safety Department by participating in activities centered around the programme. We regularly visit active sites, participate in safety meetings and site audits, and quickly respond to all reported safety issues.

CS Energy's Safety Department is staffed by experienced and credentialed professionals in the safety field who report directly to the CEO. The Safety Department manages a full programme with regular meetings across the organisation to ensure consistency. The safety team also leads a monthly cross-departmental committee to discuss the programme and evaluate its effectiveness.

A culture of safety is driven by a programme of proactive and well-planned and executed activities, which focuses on leading indicators to consistently keep safety in the foreground and a priority for all employees.

Active support of a culture of safety means the status quo is never enough; we must always be looking for improvements. We consistently evaluate and adapt our programme to keep it fresh and fight complacency. Improvements and updates continuously engage and challenge the staff.

As an example of a direct result from the review and improvement our safety programme, CS Energy has implemented an above industry standard with regard to pre-commissioning procedures for solar systems. Prior to electrical commissioning of a project, we require live testing using the best and latest technology to ensure polarity as well as the integrity of connections, terminations, wiring and the system. This process remedies issues ahead of time, minimising the risk of failure in combiner boxes, inverters and medium voltage equipment. Wiring issues can cause fires, arc-flashing or other extensive damage. By implementing this additional safety procedure, we've created a safer environment that can literally save lives.

3. Develop a consistent, standardised safety programme with regular reviews

Having a safety programme is number one, but the best practice piece is to regularly review, assess and update the programme. This is how companies identify new risks and deviations of previously documented risks.

Our safety programme promotes daily communication with field teams by sharing information, circulating daily reporting and capturing those findings in dashboard reports. Regular feedback is shared with a cross-departmental committee and the executive management team. Action items from these reports can result in new or updated hazard reports, alerts to the field, new procedures and/or other activities designed to improve the safety of staff.

Standardising the practices of the safety programme across your organisation and your projects ensures that employees have the same experience – no matter which project they are working on or what locations they are working in.

Regular reviews drive a safer environment in the field. For example, after analysing reports over several years, our safety team identified a larger percentage of slips and falls happening in the early morning after winter storms when temperatures were lower because of the presence of ice on sites. We provided cleats for our teams working in those areas during those timeframes and significantly reduced slips, trips and falls.

4. Incorporate safety awareness with technology

With today's technology, it is easier than ever to quickly distribute critical information across organisations. It is monumental that we can reach in-the-field personnel instantly with sophisticated reports and images that better enable clear communication.

Thanks to devices such as tablets and smartphones, we can now accomplish portions of our work faster and ensure that employees have the right information available to them when they need it. Technology enables project managers and field staff to receive regular email safety reports, review and post information to their own team web pages, and access libraries of information online. Through technological advances, employees can see issues other teams have experienced and use lessons learned in real-time. They can post happenings on site and keep their team members looped in. They can more rapidly gain information on changing conditions that may affect their daily activities and act accordingly.

For example, our safety manager used technology to convert a tedious compliance process into a fast and easy activity. Field staff are required to complete a report at the beginning of any new onsite activity. There is a significant amount of paperwork and time needed to meet this requirement, not to mention the lag in getting this info back to our offices to ensure compliance. Now, employees scan a bar code that instantly provides them with the necessary document. The form has now been streamlined with a simple set of questions staff can easily complete and submit with the touch of a button. It is electronically sent and compiled with daily data and posted to a dashboard report available for the safety manager's review. This now simplified process more readily delivers timely information that is utilised to drive future improvements that safeguard our staff.

5. Engage subcontractors and drive safety through their organisations

While CS Energy itself performs a portion of our work, we rely on subcontractors to provide regional expertise and deliver a level of work that meets our quality and safety requirements. This begins with selecting the right subcontractors who have prioritised safety in their businesses. As a part of the diligence process, we review their safety records and their safety personnel. Active participation in our safety programme is required of them under our contract. From day one, we immerse subcontractors in our safety programme through orientation, continuing education and site-specific safety plans that meet CS Energy standards for every project. We work for buy-in and then audit for enforcement and compliance. This process further enables the standardisation of our safety programme and drives our safety-consciousness into the subcontractors' organisation.

Final thoughts

Site safety is not a reactive thing; it is a proactive thing – you want to manage the risk out of activities before they occur.

One of CS Energy's differentiators is that it has a larger on-site field presence than its competitors. This is an added expense; however, safety issues don't happen behind a computer screen. They happen in the field. This is how we proactively manage risk and, ultimately, that reduces cost. ■

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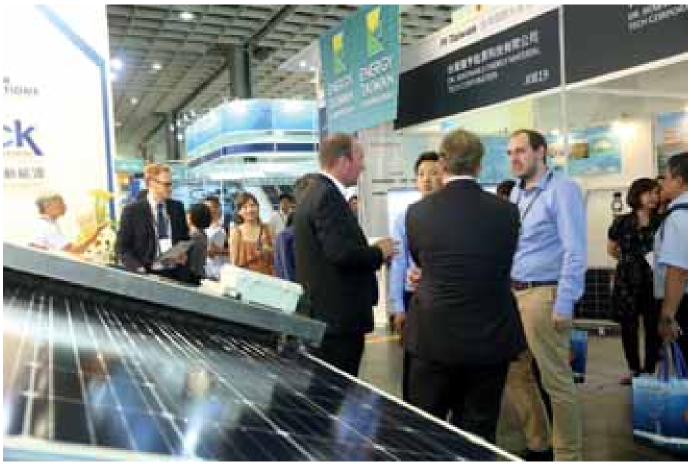
Author

Matthew Skidmore, CEO of CS Energy, has led the company's solar efforts since 2010. He spearheads operational improvements to drive productivity while reducing costs. With a track record of recruiting and retaining top talent, and the ability to discern and nurture strategic relationships into a reliable, repeat customer base, Mr. Skidmore has advanced the organisation into a reputable, nationally recognised solar development and EPC firm. He has a BS in Civil Engineering from Bucknell University in Pennsylvania.

Combines four major renewable energy business opportunities



Energy Taiwan is jointly organised by the Taiwan External Trade Development Council (TAITRA) and SEMI. The event will take place from 16-18 October 2019 at the Nangang Exhibition Center Hall 1. The exhibition will feature four major energy themes: PV Taiwan, Wind Energy Taiwan, HFC Taiwan and Smart Storage Taiwan. It is expected to attract more than 10,000 domestic and foreign buyers from related industries.

Green energy development has become a global trend. The Taiwanese government is also actively investing in the development of renewable energy. This is evidenced by the launch of its solar PV two-year promotion project, which has already surpassed its goal, generating over 1.52GW of energy. A new policy on the energy transition was launched in Taiwan to phase out nuclear power and introduce substantial power generation capacity from renewable sources by 2025. The capacity of solar PV installation is expected to reach 20GW in 2025, of which the roof type will reach 3GW. However, rooftop solar PV installation has been faster than expected, says the Energy Bureau of the Ministry of Economic Affairs, having already reached 2.8 GW and thus met its 2020 target early.

In response to green energy development opportunities, an exchange platform was set up for the renewable energy industry. TAITRA and SEMI organised Energy Taiwan for the first time in 2018. The event integrated the four main concepts of solar, wind and hydrogen energy, and energy storage. One hundred and seventy-six local and international renewable energy industry manufacturers participated in the exhibition, where they displayed solar cells and modules, wind turbine systems, wind power equipment components, raw resources, electric vehicles and fuel cells.

The 2019 Energy Taiwan is the largest and most professional renewable energy trading platform in Taiwan. The exhibition is expected to attract more than 10,000 domestic and foreign professional visitors. Visitor pre-registration is open now. For more details on the exhibition and events, please visit the official website: **www.energytaiwan.com.tw**

Visitor pre-registration

Critical requirements for PV cabling in the emerging global market

Cabling | Cable manufacturers are well placed to capitalise on solar's rapid global growth. However, to successfully exploit this continuing development, it is important to understand where growth is focused, why it is focused in these areas and the environmental and legislative challenges that it creates, writes Mark Froggatt

Solar's global growth offers opportunities to cable suppliers

The global market for solar PV energy systems is growing rapidly and, as all solar projects require extensive levels of cabling, represents a considerable opportunity for cable manufacturers. In order to gain a competitive advantage in this market, cable manufacturers must understand which parts of the world are generating the highest demand and develop cable products that meet all the relevant regulations within these locations. Understanding how PV cables perform in comparison to Low Voltage (LV) cables is essential for those seeking to develop products for the PV market, as the applications and conditions these products are specified for will create different requirements. In addition, developing an understanding of the standards to which PV cable products must be approved is of vital importance for manufacturers as the requirements of each standard may render them unsuitable for projects or applications within a specific region. In the case of IEC 62930 and BS EN 50618, these standards vary in their approach to testing and the range of cable products they test for, which means that cable manufacturers should develop their product ranges accordingly.

This paper will discuss the critical requirements of PV cable products, provide guidance on the applicable standards for testing PV cables and examine how manufacturers can produce cable products suitable for this demand, against a backdrop of the emerging global solar market.

Why the solar energy industry is growing?

The solar industry today owes the rapidity of its growth to multiple factors, rather than to one single reason. Fossil fuel pricing is expected to continue to rise over time, so future-proofing – by reducing dependence on such fuels – makes sound economic sense. Of equal importance is the pressure that commercial organisations come under to meet their environmental obligations and build a sustainable, green energy policy. This pressure comes not only from shareholders, employees and trading partners, but also from government and related bodies in the form of mandatory legislation.

Accordingly, the major energy market players are leading the way with large-scale renewable energy projects; household names including Amazon, Apple, BBC, Ikea and Unilever have all invested in major schemes.

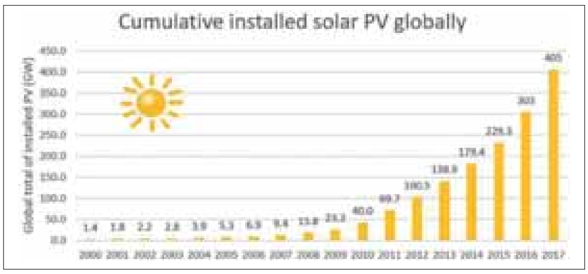
However, governments and individual consumers, as well as many other international businesses, have also contributed to driving the demand for solar energy. This need for solar energy output has been met by a reported steady growth of installed solar energy systems.

Schemes based on renewable energy sources, including solar power, are also providing valuable solutions for remote and developing locations. Providing self-sufficient, renewable energy to rural communities in the developing world helps populations to work their way out of poverty with an ability to power their homes, schools, hospitals, stores and industries.

Overall, the latest figures indicate that the global installed capacity for solar photovoltaic (PV) systems exceeded 400 GW in 2017 (as shown in Figure 1).

These factors are contributing to plenty of business growth opportunities globally. In January 2018, GTM Research reported that 53 countries had set up tendering and auction programmes allowing the supply chain to bid for opportunities to support upcoming solar projects. The research also

Figure 1. Cumulative global growth of solar PV installations. Source: SolarPower Europe



found that an additional 29 countries were planning to set up these programmes to recruit the best suppliers to fulfil their project specifications and requirements.

This statement is also reflected in figures released by the International Renewable Energy Agency (IRENA) relating to employment in the renewable energy sector. In 2017, this reached 10.3 million worldwide. The solar PV industry accounted for close to 3.4 million of those jobs and was highlighted as the largest employer of all renewable energy technologies.

What role do cables play, and what are their critical requirements?

Cables are essential to the transmission of the power generated by the solar panels. Whether they are installed indoors or outdoors, each application will call for greater emphasis on different characteristics for performance, which impacts on material requirements.

Figure 2 shows a simple domestic PV system, but the same principles equally apply to larger installations. Note in particular the use of DC cabling to interconnect the modules to one another, and to the inverter that converts their DC output to a usable AC supply. While the AC cables downstream of the inverter are usually within a building's indoor, protected environment, the DC cables are typically outside, where they are exposed to environmental stresses and, potentially, human interference.

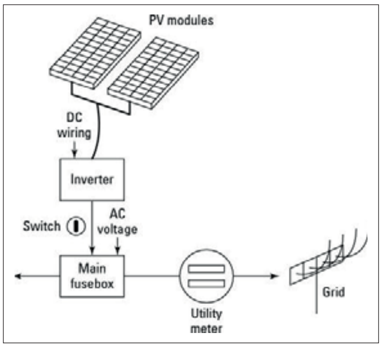


Figure 2. Simple PV system block diagram

While the technical and legislative challenges associated with overcoming these issues are significant, the opportunities they represent to those cable manufacturers that can overcome them are correspondingly impressive.

How are PV cables different to LV cables?

When a PV system is installed, both low voltage (LV) and PV cables may be specified. As these cables are designed for different applications, the performance characteristics may also differ. For example, while LV cables are suitable for indoor use and in conditions where they are protected from the elements, they are typically unsuitable for outdoor applications. An exception to the rule would be when a cable is buried, as PV cables are not designed for applications where this is a requirement. PV cables, however, are suitable for installation in trays, in applications where the cable used does not touch the ground. This can be particularly useful if rodents are a problem in the environments in which the cable is being used.

PV cabling must be able to withstand harsh conditions, for example found in the desert

LV and PV cable products also differ in the maximum temperatures in which they should be operating. This aspect should be considered at specification stage when determining if the product selected will be suitable for the specific application. Under the IEC 62930 and BS EN 50618 standards, LV cable products only need to operate continuously at temperatures of up to 90 degrees, whereas PV cable products need to be able to operate at a temperature of up to 120 degrees to ensure continued functionality if, in operation during their lifecycle, they were to reach this temperature. Ozone resistance is also mandatory for PV cables, although it is not usually required for LV cables. While LV and PV cables may perform the same essential functions of power transmission, the response to environmental conditions will be different based upon how the cable has been designed.

Which regulations apply to PV cables?

PV cable technology is still relatively new, which means that most applications will follow established international standards to ensure cable products meet high levels of quality and safety.

The industry standard warranty period provided by solar panel manufacturers is 25 years. As a result, this is sometimes also recommended as the lifecycle for solar cables. However, a set time indicative of how long a cable will last cannot be accurately given without understanding the operating temperatures and conditions. The results from a thermal endurance test, as specified in PV standards, can be used to predict life expectancy of cable products.

The location of solar projects necessitates longevity and low maintenance, particularly in the remote applications in which they are used. As such, the solar industry is heavily regulated to ensure products will be reliable and fit for purpose. As a minimum requirement, products must meet building regulations for the region in which they are being installed.

Simply performing a thermal endurance test on a PV cable product does not guarantee it will meet the required levels of quality and safety. However, independent testing and approval of products provides specifiers and end users with confidence through evidenced compliance to the applicable standards.

Following discussions with a number of firms involved in solar technology,

Abrasion resistance	Ozone resistance
Flame retardance	Proofed against chemical stresses – acids and alkalis
Halogen-free (where appropriate)	UV resistance
Humidity and water resistance	Withstanding large temperature ranges (-40°C to 90°C)
Low smoke emission	Withstanding mechanical stress: compression, tension, bending and shear load

Table 1. Attributes for which DC cabling should be tested, according to industry standards

standards have been developed which recommend the list of features shown in Table 1 that DC cables should be tested for, to maximise the potential opportunity.

A declaration from cable manufacturers that their cabling has undergone their own in-house testing is not enough – they must be able to prove to the industry that their solar products have met the pass requirements related to each of the specific tests involved in verifying the above product features. Using a testing and certification partner provides reassurance that operators and stakeholders require.

Using inappropriate cable shortens a project's lifespan and many solar projects are being supported by local governments and, as such, can be accountable to public stakeholders for the return on financial investment.

While some certification bodies have developed their own standards for testing PV cable products, the main standards recognised internationally and specifically relevant to solar cable products used in DC apparatus are IEC 62930: ed 1.0:2017 and BS EN 50618:2014.

EN 50618 only applies to cable products that use flexible tin-coated copper conductors with a single core and cross-linked insulation and sheath produced with low smoke, halogen free (LSHF) materials, while IEC 62930 has extended this scope to cover single-core cross-linked insulated power cable products manufactured with or without LSHF materials. Both standards set out exacting requirements for testing PV cable products in reflection of the challenging conditions the cable products will be specified for.

While these standards have similar critical requirements, there are significant differences in the materials permitted and the range of the conductor size that can be tested, which we will discuss in the next section.

How can I produce cables that meet solar PV system requirements?

At a technical level, innovations in compounds and extrusion technology are now available to help cable manufacturers meet the solar industry's unique specifications. Many cable manufacturers are working closely with project specifiers to manufacture cables that meet the design and local manufacturing standards' requirements.

In order to produce cable products that will meet solar PV system requirements, cable products should be designed to meet the requirements of IEC 62930: ed 1.0:2017 and BS EN 50618:2014. These specific requirements will now be explored in more detail, where each standard's emphasis on the use of some materials over others differs.

The first requirement is for cable products that are used with Class II equipment. Defined in IEC 61140 as equipment with double insulation that does not require a safety connection to the electrical earth, Class II equipment typically applies to appliances including televisions, DVD players and power tools. BS EN 50618 is suitable for testing these types of cable products; however, IEC 62930 does not make provision for this. Any appliances using PV cable products with Class II equipment should therefore be tested to BS EN 50618.

A further consideration when seeking to understand specific characteristics and the different emphasis each standard places on them is the size of the cable conductor. Where BS EN 50618 only specifies a conductor size range of between 1.5 and 240m^2, IEC 62930 allows for a wider range of 1.5 and 400m^2. It is worth noting that even if a cable product has a large diameter, the conductor size may be small due to being surrounded by insulation, bedding and wire armour. The decision as to which standard cable products should be tested to, therefore, should not only be based on conductor size alone.

Solar cable installation

The main difference between the standards is the materials permitted for testing, as BS EN 50618 only permits testing of cable products manufactured with LSHF materials. These types of cable products are designed to give off low emissions of smoke and corrosive gas when they come into contact with fire. They are often specified for public buildings as they reduce the risk posed to public safety, in the event of an emergency. By comparison, IEC 62930 permits materials with or without LSHF materials to be tested, including PVC cable products. While this material gives off thick smoke and toxic fumes when burned, PVC, or a modified form of PVC, may be more appropriate for customer requirements. For example, PVC cable products may be better suited to carry power from solar panels to a water treatment facility, as they provide greater chemical resistance than their LSHF counterparts to the chemicals used in the water treatment.

Thermal endurance testing is mandatory as part of IEC 62930 and BS EN 50618. This test is designed to determine a cable's lifetime and involves testing any PV cable product up to 120°C for 20,000 hours, to simulate how the product will perform in operation. When these standards were initially being developed, the thermal endurance test generated some controversy as its main measure is to demonstrate how long the cable will operate for before it reaches the defined threshold; all within controlled conditions. As many PV cable products are usually installed in extreme conditions, the results of this test may be less conclusive than more established tests such as the hot pressure test, which is used to check that sheathing and insulation materials are resistant to indentation at elevated temperatures. Nevertheless, submitting cable products for a thermal endurance test can further aid in evidencing cable quality.

While cable products may be successful in passing a thermal endurance test, consideration should also be given to how other characteristics will be impacted by the conditions they are operating in. For example, solar panels are often installed in coastal or desert locations where the temperature may rapidly drop, which could cause cables to crack or bend as

Electrical engineer inspecting photovoltaic cables connected to solar panels

temperatures drop below those in which the cable products have been designed to operate. If cable products have been produced using poor-quality materials, they may absorb significant amounts of moisture, dulling the performance of the cable products by reducing the current they can carry. These examples demonstrate the need for PV cables to be suitably tested for performance across a wide range of characteristics to verify quality and suitability for installation in the specified conditions.

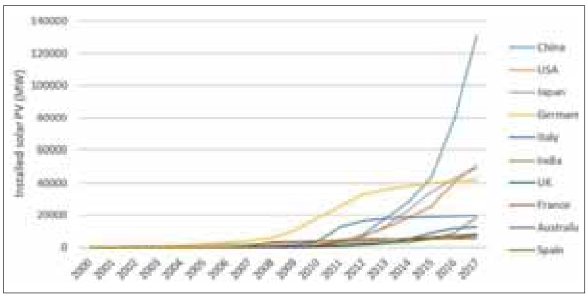
How is demand distributed globally?

As early adopters of solar PV systems, Germany was recognised as a leader in solar installations for a decade up until 2015, after which it was overtaken by China (see Figure 3). China's solar installation started to take off sharply in 2012, and in 2017 their newly installed base totalled significantly more solar capacity than the past top nine leading countries combined. Relative newcomers Japan and the USA have also overtaken Germany and have been tracking at a higher rate of installation. The data demonstrates that the race to produce renewable energy-driven initiatives, is truly a global one. It is therefore essential that specifiers, buyers, cable distributors and manufacturers take note to use product that is compliant with the international and local standards, to ensure that the product supplied is commercially fit for purpose.

Cable manufacturers looking to break into the solar market should carefully consider the end-user requirements when designing their cables, as the standards used to verify cable quality are specific to different types of materials. As mentioned above, BS EN 50618 is only applicable to LSHF cable products, while IEC 62930 permits materials that are not produced using these materials, which could provide a manufacturer with an indication of which of their existing product variants may be best suited to specific markets. Depending on the specification that cable products need to meet and which of the standards are favoured in the market, this should inform design and production decisions.

For example, if buildings in the selected market have a high fire risk or cable products will be installed in enclosed spaces, LSHF cable products should be used to minimise the risk of building inhabitants being exposed to toxic fumes and gases during a fire. However, if cable products are designed to be used on the exterior of a building, as many PV cable products are, this would create different requirements for the cable product. In this case, PVC may be deemed a more suitable material to use as it demonstrates greater abrasion resistance and durability than its LSHF counterpart.

Figure 3. Cumulative installed solar PV, top 10 countries, 2000-2017. Source: SolarPower Europe



Conclusion

This article has shown how multiple factors are contributing to the solar PV market's rapid growth. Over time, and as knowledge is rapidly developing, we are seeing a vast improvement in the quality and performance of the cables used in the solar industry. In years gone by these aspects have not fared as well as anticipated, therefore as the industry continually grows, we can also expect to see the technologies used to manufacture cables advance, to ensure reliable product enters the market. This growth is creating a healthy demand for external DC cabling, and a great opportunity for cable manufacturers that can overcome the challenges associated with meeting the market's requirements. These manufacturers can obtain a competitive edge in this process by working with BASEC to gain independent product certification and approvals to demonstrate that the products supplied into the market are compliant with all of the necessary regulations.

The potential rewards for cable manufacturers who make this investment are considerable; as Walid Halty (Dvinci Energy, Forbes, May 2018) comments: "Today, Solar is the #1 most bankable sustainable technology, which has turned the industry into a gold rush." ■

Author

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Against great odds: solar power in the Antarctic

Many countries have installed research bases in the Antarctic to conduct various studies in this very special landscape and its unique climate. Temperatures below -89°C, winds over 200km/h, extreme variances in hours of sunlight, with up to 16 hours in the summer and only two during winter, pose tremendous challenges for both research teams and equipment. PV connectors from Stäubli are part of a demanding new field of application: installing solar power in the Antarctic.

The Uruguayan government is a strong advocate for the integration of renewables and following a 10-year programme to reduce its dependency on fossil fuels. 97% of the electricity now comes from hydroelectric, solar, wind and biomass. The country has been maintaining a research base in the Antarctic for over 30 years. The Artigas base, opened in 1984, is home to 10 research scientists and 15 crew members in summer.

The base was traditionally powered by diesel generators. Besides the environmental impact, the logistics involved made the use of fossil fuels an inefficient and costly solution for generating energy.

Tecnogroup is a conglomerate of Uruguayan companies with extensive international experience in the development, procurement, construction, operation and maintenance of renewable energy plants. The government selected Technova Renovables, a Tecnogroup subsidiary, to review the potential and lead on the integration of renewables at the Artigas Base. The project included the delivery and installation of a pioneering solar system designed to withstand the environmental challenges within this delicate ecosystem. The importance and challenging nature of project required collaboration between several partners, including the government and the energy ministry MIEM, the local utility company, UTE, and the Instituto Antártico Uruguayo.

Installing solar power in the Antarctic has been a pioneering project of the Uruguayan government and is part of a program to extend the use of renewable energies. PV connectors from Stäubli ensure safe and reliable power transfer.

The challenge

The Antarctic is one of the most inhospitable places in the world. Spanning 14,000 square kilometers and with extreme climatic conditions including temperatures as low as 89.2°C and winds of more than 200km/h, the challenge was to develop, install and test the performance of PV technology in such a fragile environment. Due to the variances in sunlight hours, the timeframe was very limited: the installation had to be completed before the seasons changed.

The solution

To successfully implement the pilot plant with 1.2kWac, all partners worked closely together. Both the extreme temperatures and variances in hours of sunlight had to be considered for the installation of the PV system: the solar panels were vertically mounted onto the wall of an existing machine room, with a 90° tilt and N orientation and at a considerable height to overcome heavy snow accumulation as well as wind present at the site.

The success of the project is based on thorough planning, mutual harmonization and the careful selection of components to be installed. To secure constant and dependable energy feed-in, Tecnogroup relies on PV connectors from Stäubli. The MC4-Evo 2 connectors have been proving their worth from the very beginning and withstand the extreme, unprecedented climatic conditions.

MC4-Evo 2 connection of solar modules for safe power transmission under harsh environmental conditions

Due to a long and fruitful business relationship and trust in Stäubli components that are already in use in several other systems, including large-scale PV plants, the choice was clear for Marcelo Mula, Executive Director of Tecnogroup: "Knowing that you are working with experts in their field is crucial for the successful implementation of PV projects. We have been working with Stäubli for many years and rely on high-quality connectors that ensure a safe and reliable connection as well as steady energy feed-in."

The effective implementation of a PV system will not only help the Artigas Base reduce the environmental impact of its operations as well as OPEX costs, but also represents a further milestone in the global expansion of renewable energies.

https://tecnogroup.com.uy/es/Pages/WhatWeDo
www.staubli-alternative-energies.com/

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About Stäubli

Stäubli offers innovative mechatronic solutions in three core areas including Connectors, Robotics and Textile. Founded in 1892, today Stäubli is an international group headquartered in Pfäffikon, Switzerland with more than 5,500 employees worldwide. Stäubli has a presence in 29 countries with production companies, sales and service subsidiaries and is supplemented by agents in 50 countries.

As a world market leader in the field of connectors, Stäubli manufactures quick connector systems for all types of fluids, gases and electrical energy. The Electrical Connectors product portfolio (formerly Multi-Contact) ranges from miniature connectors to high-performance connectors for power transmission, industrial automation, transportation, test and measurement. In Photovoltaics, Stäubli is the global market leader with its MC4 connector components. The core of all Stäubli electrical connectors is the unique MULTILAM technology.

www.staubli.com/electrical

A pioneering project: PV in the Antarctic

Benchmarking inverter performance and reliability with a new PVEL Scorecard

Inverters performance | Inverters are the leading source of corrective maintenance activity in PV power plants, yet independent testing to inform procurement decisions remains the exception rather than the norm. Michael Mills-Price and Jenya Meydbray of PVEL describe how a new inverter testing regime is seeking to set quality benchmarks for this increasingly critical part of the PV system

Inverters are the number one driver of PV project profitability. Every time a solar inverter underperforms or shuts down unexpectedly, the entire PV system produces less energy – or none at all. Maintenance costs are compounded by the financial consequences of energy shortfall.

Modern inverters contain hundreds of complex, software-driven components that monitor and control the most vital operations of a PV system. Like all electronics, these components degrade over time. But what is a reasonable lifetime expectation – and how do PV inverter buyers generate reliable predictions? Only about 25% of the world's total installed PV capacity has operated for more than five years, so the industry lacks long-term real-world data. While most inverters today are warranted for 10 years, results from the field show that many products do not last that long.

PVEL's inverter testing aims to provide investors with better intelligence on inverter performance and reliability

As systems age and inverters degrade, the industry is beginning to recognise the importance of inverter selection to a project's long-term economic performance. Low-performing inverters that generate unexpected, ongoing maintenance expenses can ultimately become costly for asset owners. Due to the underlying complexity of inverter design and construction as well as their broad functionality, inverters are also more vulnerable to reliability issues than any other PV system component. Developing accurate inverter lifetime and cost of ownership predictions should not be an afterthought.

PV Evolution Labs (PVEL) is one of very few independent labs that performs extended reliability and performance testing on PV inverters. We found that one-third of the products we tested through our PV Inverter Product Qualification Program (PQP) failed key safety and performance tests – even though all of the tested products were certified by IEC and/or UL. In response to these findings and to growing demand for inverter data, PVEL published its first PV Inverter Scorecard in May 2019.

This first Scorecard was developed with two main goals: first, to educate PV asset owners, project developers and investors about the complexity and inherent risks associated with inverters and, second, to introduce the PV buyer and asset owner community to inverter reliability and performance testing that provides critical insights for inverter diligence. It is also the first inverter benchmarking report based on independent test data that is available to the public. This article highlights key insights from PVEL's Scorecard to explain why and how PV equipment buyers can use objective reliability and performance data to mitigate the financial consequences of technology risks inherent to inverters.

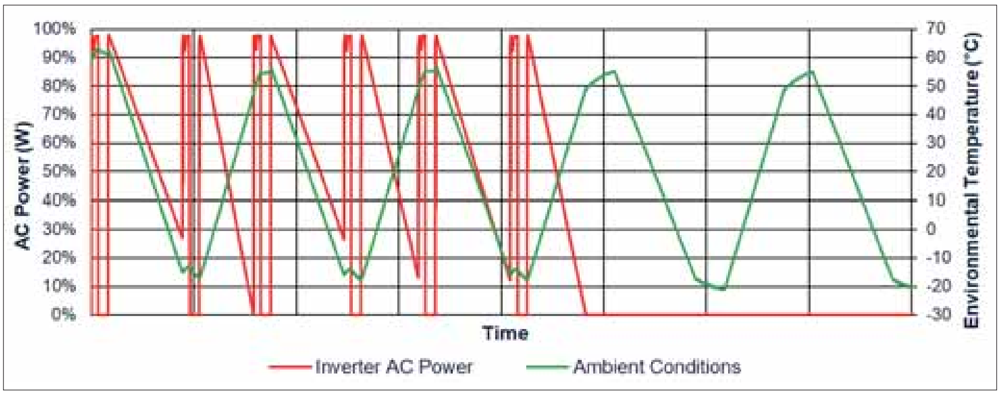

Figure 1. The figure shows an inverter that failed to operate after only 30% of the powered thermal cycling test sequence was complete. It was unable to return to operation

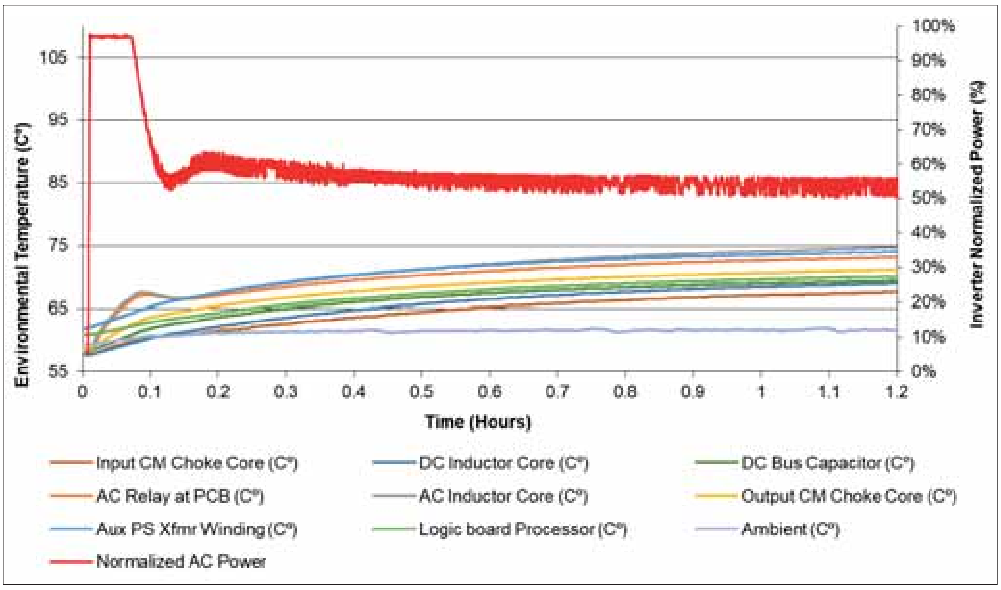

Figure 2. The figure shows an inverter that de-rated to avoid significant temperature increases of internal components during the high temperature test – even though the ambient temperatures sustained were within its operational window

Inverter procurement today

Although inverters are the leading source of corrective maintenance tickets in PV power plants and the top cause of energy outages [1], very few PV project developers, financial institutions and asset owners to date require independent testing that assesses inverter reliability and performance. Historically, due diligence expectations and testing requirements for inverters have been much less rigorous than those for PV modules.

The challenge is that many project stakeholders lack the institutional knowledge and data required for in-depth technical due diligence of inverters. Instead, buyers and investors rely on certifications, brand names, datasheets and warranties to evaluate inverter bankability. PVEL's PV Inverter Scorecard proves that these data sources are not sufficient for strategic inverter procurement where long-term financial returns are at stake. This is especially true for cost-sensitive projects that cannot weather the financial impact of higher than expected operations and maintenance expenses.

About the PV Inverter Scorecard

The 2019 Scorecard is based on independent testing of 35 inverter models produced by 12 different manufacturers. Tested products include string inverters (both three-phase and single-phase), microinverters and power optimisers. Each inverter evaluated for the Scorecard underwent testing through PVEL's Product Qualification Program (PQP) for inverters. Results from 14 tests are presented in the Scorecard. Highlighted results from seven of these tests are discussed below.

All inverters were tested in the same way, leveraging consistently calibrated equipment and in consistent laboratory environments. Inverters submitted for testing through PVEL's PQP are witnessed in production – from the opening of raw materials packages through every step of the process, including final packaging with tamper-proof tape. This ensures that hand-picked samples are not sent for testing. The inverters that ranked as Top Performers for each test are listed by name and model in the Scorecard, which is available as a free download at www.pvel.com/inverter-scorecard, and summarised in the box towards the end of this article.

Test results: thermal performance

Temperature directly impacts an inverter's electrical performance and long-term reliability; therefore, all inverter manufacturers provide product-specific maximum and minimum ambient temperatures for operation. The individual electrical components within inverters also have maximum and minimum temperatures at which they operate. Temperature conditions can vary widely in the field and inverter components

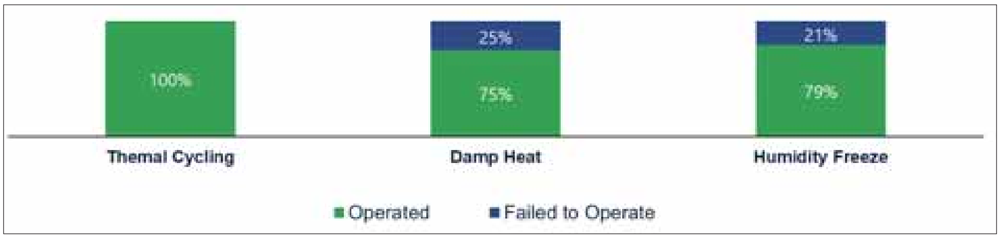

Figure 3. The share of inverters that failed to operate following each passive chamber test. Many of the inverters that were still operational following testing operated in a reduced capacity

Figure 4. Delamination and internal corrosion in an inverter following passive chamber testing

may be susceptible to thermal drift, a phenomenon which results in individual components performing differently than expected. Inverters are designed with built-in safety mechanisms that prevent these internal components from reaching their maximum allowable temperatures – but these safety mechanisms should only be triggered when absolutely necessary because of their impact on energy yield.

Manufacturers design inverters with these safety mechanisms because degradation rates accelerate when components exceed their temperature limits during operation. Operating beyond allowable limits reduces the lifetime of the component and ultimately the inverter itself. To avoid this, inverters de-rate, or reduce power output, when the temperature limits of an internal component or subsystem are exceeded. While this de-rating process is important for inverter reliability, it should only occur when the inverter is exposed to conditions outside of its operational window. When inverters de-rate, they convert less energy than expected from the PV array. This results in reduced energy yield and financial losses for the asset owner.

Thermal performance tests are used to measure and document the thermal de-rating of inverters. The tests are among the best methods of determining whether an inverter's performance accurately reflects the temperature specifications on its datasheet. To perform these tests, the inverter is placed in an environmental chamber and connected to a solar array simulator. Next, the following conditions are applied:

- **Powered thermal cycling.** Thermal cycling is performed across the full operational temperature range while the inverter is powered from minimum ambient temperature to maximum ambient temperature.
- **High temperature operation.** The maximum operational temperature is sustained while the inverter is powered.
- **Low temperature operation.** The minimum operational temperature is sustained while the inverter is powered.

As these tests are conducted, PVEL measures the temperatures of multiple individual components using thermocouple sensors. These temperatures are then compared to the component datasheets to verify design parameters and determine whether the inverters de-rated while operating within their specified temperature windows. Not all inverters tested were able to operate without de-rating – and some were not able to continue operating during the tests (See Figures 1 and 2).

As pricing pressure on inverter manufacturers intensifies, some producers may utilise smaller, less expensive and less robust components. For example, using a silicon chip with narrower temperature or voltage limits may reduce costs in the short term, but could ultimately cause problems for system owners as the cheaper components prove less reliable when exposed to various thermal conditions.

Test results: passive chamber testing

Inverters contain circuit boards, silicon chips and integrated products that can age and fail when exposed to sunlight, rain, temperature swings, humidity, snow and other common environmental conditions. Unpowered environmental chamber testing evaluates the impact of these environmental stresses on inverters and their components. PVEL's goal with these tests is to assess the product construction, Bill of Materials and product design of an inverter.

Passive chamber tests include thermal cycling, humidity freeze and damp heat. The test procedures align with and expand upon the IEC 61215 test standard, one of the most common certification requirements for determining the safe operation of PV modules. Importantly, PVEL's chamber tests reproduce failure modes and reliability issues commonly observed in the field, including coating delamination, corrosion, water condensation in wiring compartments, discoloration and melting of external displays and controls, and electro-mechanical fatigue of solder joints and electrical connections.

Passive chamber testing results (Figures 3 and 4) indicate:

- 25% of inverters failed to operate after damp heat;
- 21% of inverters failed to operate after humidity freeze;
- A significant population of inverters that operated following these tests were only able to operate in degraded,

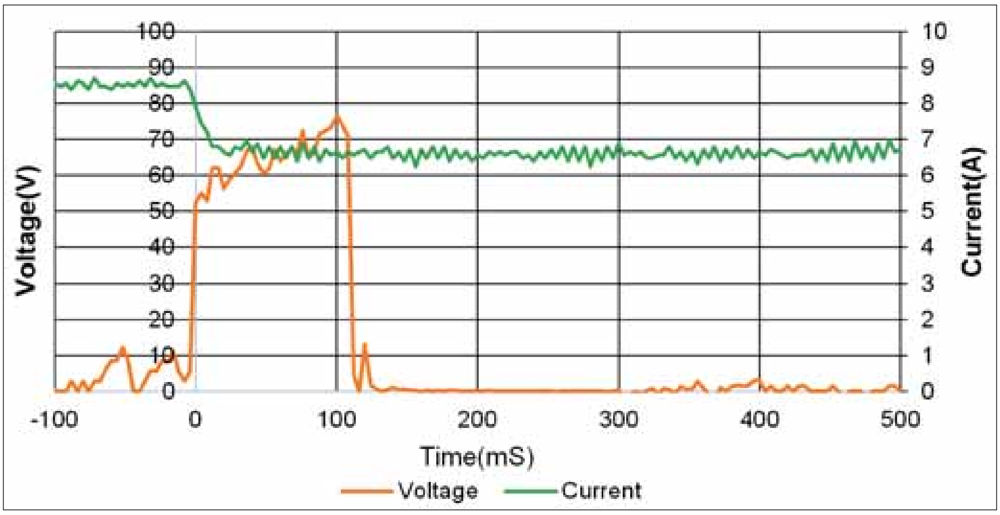

Figure 5. The figure shows a properly detected and interrupted arc fault. It highlights the ability of some inverters to effectively identify and respond to arc faults within the required time range, before the device or the array incurs any damage

less efficient states;

- The most common failure modes were faulty moisture protection of a component, delamination and internal corrosion.

Successful performance in passive chamber tests indicates that products have robust construction and design that can withstand common field conditions. While all inverters that are deployed to PV sites should pass these tests, PVEL's data shows that this is not always the case.

Test results: ground and arc fault

Safe operation is fundamental to the economic success of a PV system, but electrical arcs can occur if electrical conductors are exposed to the environment. Exposure can occur as systems age; for example, when insulation around system wiring degrades, connectors age or come loose on module backsheets fail and start to crack. Properly detecting arcs is part of an inverter's core operation.

In PV systems, electrical arcs can manifest as fires– but only when the inverter fails to detect them and rapidly shut the system down. In extreme cases such as with fires, electrical arcs pose considerable safety risks. They can also result in significant, irreversible damage to the entire PV system. Inverters detect arcs by sensing their characteristic signature, or fingerprint, in the frequency domain. However, this fingerprint may be masked because it is dependent on the location of the arc in the PV array. PVEL's ground and arc fault testing exposes the inverters to arcs at several locations within the array and documents the response of the inverter.

PVEL's fault tests are conducted at our outdoor test site. The inverters are subjected to multiple ground and arc fault conditions on a grid-connected PV system. The inverter is monitored to track proper system shutdown. One third of the inverters evaluated for PVEL's Scorecard failed to detect at least one fault during testing – even though they passed certification testing (see Figure 5). This finding is alarming given the importance of fault detection to the safe operation of PV systems.

Independent test results in context

Every solar project's financial model depends on energy yield forecasts that predict safe, reliable power generation for decades. They also depend on reasonably accurate estimates of operations and maintenance costs. PVEL's testing shows that inverters are not always equipped to meet these expectations. Some do not even meet the minimum requirements specified by datasheets and certifications.

Many buyers and investors rely on warranties to protect them financially when inverters fail. This strategy can quickly backfire when an inverter manufacturer exits the market. Additionally, replacing inverter products may be nontrivial. Imagine searching for a new 600V central inverter today. If a suitable replacement is not available, the entire PV system may require rewiring to prevent electrical mismatch.

A 2017 study assessed the true cost of inverter ownership using data from 400 failure reports (see Figure 6) and found that two of the four inverter manufacturers assessed generated far higher operations and maintenance costs than predicted [2]. In some cases, annual maintenance expenses were underestimated by more than 500%.

The study goes on to note: "In view of the high costs associated with inverter

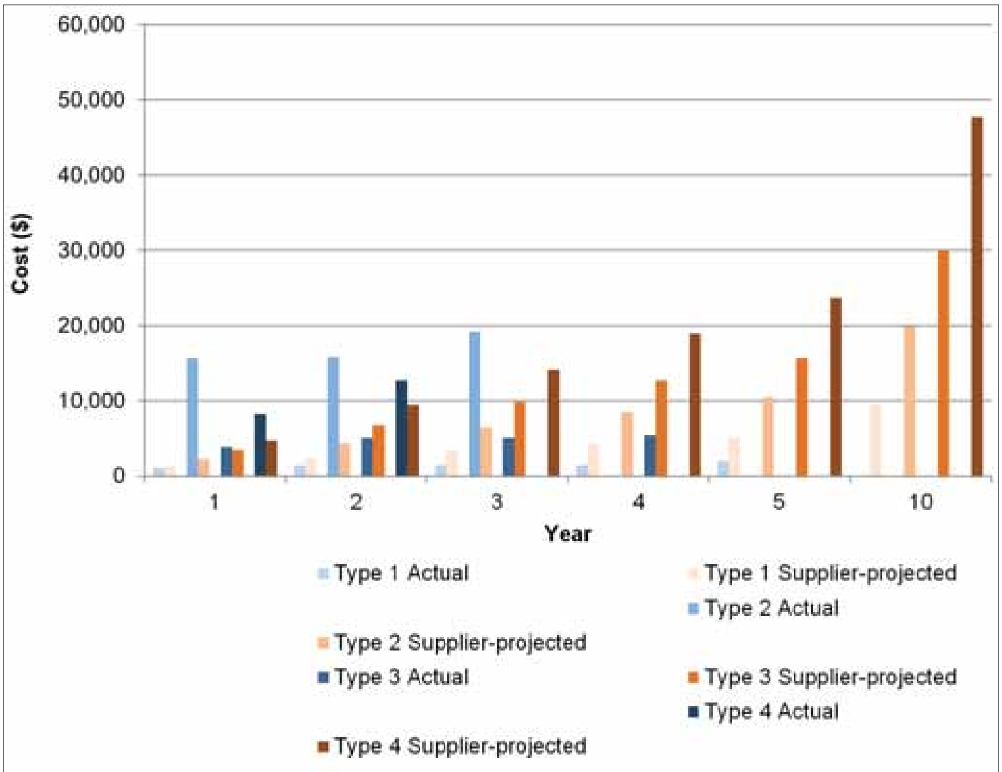

Figure 6. Comparison of the cumulative cost of inverter ownership to cost estimates provided by manufacturers. Actual costs are only provided for years where data is available [2]

PVEL's Top Performer inverters

The scorecard's 14 tests are broken down into five categories: passive chamber testing; thermal performance characterisation; performance testing – efficiency; performance testing – operational window; and field testing. Where appropriate, 'Top Performers' are identified for each test – specific inverter makes and models that have performed particularly well. The makers and inverter models awarded Top Performer status in the inaugural scorecard are detailed below:

Passive chamber
In the Passive Chamber tests, only two companies were awarded Top Performer status: Delta's single phase string inverter M8-TL-US and SMA Solar's SB7.7-ISP-US-40, another single phase string inverter.

Thermal performance characterisation
Three different companies' products were Top Performers in the powered thermal cycling category – Delta's single-phase string inverter M8-TL-US, Schneider's Conext CL-60A string inverter and SMA Solar's SB7.7-ISP-US-40. PVEL highlighted an example of an inverter that failed 30% through the test sequence with an inability to return to operation.

In the high temperature operation category, three different companies' products were Top Performers: Delta M8-TL-US, Fronius' Symo 24.0-3, a transformerless three-phase string inverter, and Huawei's SUN2000-11.4KTL-US string inverter.

There were two Top Performers in the low temperature operation test: the Delta Solivia 3.8 TL and the Huawei SUN2000-11.4KTL-US.

Performance testing: efficiency
In the performance efficiency test category, which analyses MPPT efficiency, conversion efficiency and energy harvest, PVEL noted the tests set out to demonstrate whether or not an inverter can actually perform as expected based on product datasheets when deployed in the field.

Three different companies' products were Top Performers in the MPPT efficiency test: Delta's M8-TL-US, Huawei's SUN2000-30KTL-US and Schneider's Conext CL-60A string inverter. PVEL noted that Top Performers in this test sequence had a 98-99% response rate for all three test conditions.

Top Performers in the conversion efficiency tests were Huawei's SUN2000-30KTL-US and SUN2000-375W-USP0, and Schneider's Context CL-60A.

In the energy harvest tests, Top Performers were Huawei's SUN2000-28KTL and SUN2000-30KTL-US, also accompanied by Schneider's Context CL-60A.

Performance testing: operational
In the performance operational tests, which include operational envelope and transient response, PVEL noted that "inverters that have wide DC input ranges can support a more diverse set of possible stringing configurations, allowing flexibility for the designer or installer of the system".

PVEL only scored Delta's M80U inverter in the AC operational envelope test and the same inverter in the DC operational envelope category with Schneider's Conext CL 25000NA inverter.

In the transient response test, Top Performer status was given to Delta's M8-TL-US, Fronius' Symo 24.0-3 and Huawei's SUN2000-11.4KTL-US inverter.

Field testing
In the field testing category, PVEL said that the PQP determined whether an inverter would operate safely and continuously in real-world conditions. The tests include a ground and arc fault tests and a 30-day runtime in operation.

The three Top Performers in the ground and arc fault tests were Delta's M8 TL-US and Solivia 3.8 TL inverters, as well as Fronius' Symo 24.0-3 inverter.

In the 30-day runtime tests, only two companies' products were given Top Performer accreditation: Huawei's Sun2000-11.4KTL-US and SMA Solar's SB7.7-1SP-US-40.

Summary
In summary, the three most-cited Top Performer companies were Delta with 10, Huawei with nine and Schneider with five.

On a product basis, the three most cited Top Performers were Delta's M8 TL-US inverter with four accreditations, Huawei's Sun2000-11.4KTL-US also with four and Fronius' Symo 24.0-3 with thre accreditations.

By Mark Osborne

failures, understanding the root cause of component failures, methods to access or ensure reliability and forecast lifetime of the power conversion electronics and their components through testing and quality standards becomes vital." [2] The testing conducted through PVEL's PQP and the results presented in the Scorecard provide the data developers, banks and asset owners need to better predict the long-term reliability of inverters.

Next steps

As the solar industry matures and asset owners focus more on total system lifetime performance – and not just initial costs – inverter reliability is becoming increasingly vital. PV inverter service life expectations began at less than five years in the 1990s. Today the market expects a central inverter to last at least 20 years. Inverters were once expected to convert DC electricity to AC electricity – and not much else. Today they communicate with complex monitoring systems and diagnose system performance problems in real-time.

Despite this dramatic technical evolution, inverter procurement strategies have not evolved significantly over the past decade. This is a risky approach for PV asset owners and investors because independent testing proves that not all inverters live up to expectations. Instead there is a range of performance, functionality, efficiency and reliability across commercially available products.

When PVEL began testing PV modules in 2010, we observed tremendous variability in performance and reliability across manufacturers and tests. The product landscape was very similar to the market for inverters today. As the buyer community began to recognise the variability of PV modules and the advantages of independent testing in identifying the best products to buy – as opposed to brand, warranty terms and datasheets alone – module quality has improved. We hope to see inverter quality similarly improve over time. ■

To learn more about PVEL's inverter testing services or to access the full test reports behind PVEL's PV Inverter Scorecard, contact Michael Mills-Price at michael.millsprice@pvel.com

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[1] Hacke, P. Lokanath, S. Williams, P., Vasan, A., Sochor, P., TamizhMani, G., Shinohara, H., Kurtz, S. 2017 "A status review of photovoltaic power conversion equipment reliability, safety, and quality assurance protocols", Renewable and Sustainable Energy Reviews, Vol. 82, No. 1, pp. 1098

[2] Hacke, P. Lokanath, S. Williams, P., Vasan, A., Sochor, P., TamizhMani, G., Shinohara, H., Kurtz, S. 2017 "A status review of photovoltaic power conversion equipment reliability, safety, and quality assurance protocols", Renewable and Sustainable Energy Reviews, Vol. 82, No. 1, pp. 1098

Authors

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Michael Mills-Price is head of PVEL's inverter and energy storage business. He has nearly 20 years of renewable energy industry experience and has authored over 30 technical innovations, patents and whitepapers to advance the state of the industry. He specialises in power electronic devices and the interface of renewable technologies to the broader electrical power grids. Michael joined PVEL team in 2014 to create a suite of performance and resiliency inverter testing strategies to benchmark commercially available products.

Installing solar on water opens up huge new possibilities for the technology

Credit: Seaflex

Unlocking solar's new terawatt opportunity

Floating PV | Floating solar has caught the industry's imagination in recent years, opening up potentially limitless new opportunities for PV installations in land-constrained parts of the world. Ben Willis reports on the work underway to address questions about the performance and reliability of water-based solar installations

From ground zero in 2007, the total capacity of floating solar installations worldwide had grown to around 1.3GW by the end of 2018, according to recent analysis by the Solar Energy Institute of Singapore (SERIS) for the World Bank. That's a solid start for an emerging market segment that many hope will become the 'third pillar' of the PV industry, alongside ground-mount and rooftop solar. Around the world, there are some 400,000 square kilometres of manmade reservoirs alone; if just a fraction of these bodies of water were to become home to floating PV arrays, all of a sudden a key constraint that has prevented many regions of the world from embracing solar – namely, land, or lack of it – would become irrelevant, cracking the technology and its many benefits wide open to a host of new users.

Unsurprisingly, interest in floating PV is strong and growing, observes SERIS director, Dr Thomas Reindl, but plenty of obstacles still stand in the way of its full potential being realised.

"What we have witnessed recently, is a strong interest from governments and private actors to develop floating solar projects across multiple regions. Such projects are no longer focused on Asia, but projects are being considered and constructed in Europe, America and to a lesser extent in Africa. The Middle East has also shown a recent interest in the technology, where water evaporation losses are significant. Another recent development is the announcement from various consortia or governments to start research and piloting projects in seawater," Reindl says.

"Many actors across the public and private sector, however, agree that there is a lack of data about the existing projects (confidentiality is often an issue). If solved, data could help to understand better the cooling effect in various climates, leading to improved modelling of the energy yield and thus cash flows."

Better data on the performance benefits of floating solar is certainly one key factor that would help it live up to its promise. Yet, as a still-nascent market segment, the reality is that floating PV faces numerous other challenges – technical, operational, financial – that it must overcome on the road to mass deployment. With the extensive experience and knowledge the solar industry has collectively amassed in becoming a plus-500GW global market, the good news is that none of these should be seen as insurmountable. This article explores some of the efforts underway to help floating solar live up to its considerable potential.

Hardware

Modules

According to SERIS' report for the World Bank, there are no particular standards for modules deployed in floating solar projects, and the most commonly used are framed glass-glass modules, which withstand moisture ingress comparatively well. Frameless modules have also been used in some projects to date, as these offer the best resistance to potential-induced degradation (PID) in high humidity situations.

PID, a problem that has afflicted ground-mount solar installations in particular, is something of an unknown where floating solar is concerned. Humidity is one factor that increases the likelihood of PID in land-based installs; the probability of humidity being higher around water implies it may be problematic for floating arrays. But the jury is out on this, says Reindl.

"PID is a known issue for several large PV farms, and could cause severe setback in terms of project profitability. Given the higher humidity on water, it could be a pitfall, but there are no reports on that happening yet. FPV systems in Singapore's Tengeh test-bed [operated by SERIS] are being closely monitored for PID issues. Theoretical calculations suggest that the PID stress is not much more severe than those specified in standards IEC 62804-1, so modules are expected to perform well if they are properly certified as PID-free," he explains.

Mounting type	Advantages	Disadvantages
Pure-float configurations These use specially designed buoyant bodies to support PV panels directly (Figure 1).	-Easy to assemble and install -Can be scaled without major changes in design -Few metal parts required, minimising corrosion -Adapts to wave motion and relieves stress	-Modules mounted very close to water, reducing air circulation and cooling effect from evaporation. It also generates a high-humidity environment for PV modules and cables -Not cost-effective to transport pure floats over long distances, so they may need to be made in nearby facilities -Constant movement may cause stress and fatigue to joints and connectors
Pontoons + metal frames These use metal structures (frames or trusses) to support PV panels as with land-based systems. The structures are attahed to pontoons, which provide buoyancy; special floats are not required (Figure 2).	-Simple concept -Floats are easy to make and can be easily sourced locally -Wave movement between PV modules is less variable, thus reducing wear and tear on module connection components and wires.	-With more rigid structures, waves cause stress to concentrate at certain points -Structures are more difficult to assemble -Access for maintenance can be difficult in certain designs

Table 1. The pros and cons of the two most common flotation designs used in FPV installations. Source: World Bank/SERIS

Credit: SERIS

Figure 1. Ciel et Terre's floating solar mount is an example of the pure-float design

Credit: SERIS

Figure 2. Takiron Engineering is one company producing the pontoon + metal frame variant of the floating solar mounting structure

Floats

Another critical area where more work is required concerns arguably the key components in a floating PV installation – the floating structures themselves. Currently, a number of companies are producing floats for solar arrays, following two main generic design types (see Table 1 and Figures 1&2) but as a comparatively new technology, without a long track record in the field, the SERIS report lists floats as a possible technology risk that must be addressed through more rigorous testing and certification to prove their durability.

"Standards create methods to measure a specific property that can be related to another difficult-to-measure property that is a quality or performance indicator," says Reindl. "For example, the thermal cycling stress test for modules will indicate that limited degradation of the performance of a module after a specific number of thermal cycles will probably indicate this module can last longer than 20 years under normal circumstances. Whoever does this test, the chances are high they get comparable results.

"This we also need for floats: standard reproducible measurements that can be related to a quality or performance parameter, so I can measure and say objectively float A is better for this measurement than float B. If these parameters are well selected it will create a trend in the industry to focus on these parameters and create better and better floats."

Mounting

A further consideration in the design of floating solar arrays concerns the tilt angle of modules. Typically, modules in a floating array are set at a limited tilt to reduce problems associated with wind loading. This can have implications for achieving the best energy yields from floating installations, particularly in high-latitude regions where a generally steeper tilt angle is optimal to maximise exposure to the sun.

Shankar G. Sridhara, CTO at REC Group, which has been an early pioneer in developing floating solar technologies, explains: "The angle of module installation on the floating system is often predetermined in its design and may leave little room for adapting to the best angle for local conditions. Other systems may allow a degree of flexibility. This means that the complete project, including installation time, needs to be weighed up against the angle of installation and any associated impact this has on the expected yield and levelised cost of energy."

Performance and operation

According to the SERIS/World Bank study, operation and maintenance (O&M) costs for floating PV arrays should not be inherently higher than for their ground-mounted counterparts. Nevertheless, certain factors particular to floating arrays are likely to come into play where O&M is concerned, necessitating some new skill-sets, techniques and procedures, according to REC's Sridhara.

"O&M is certainly an important factor also when it comes to corrosion, especially in more aggressive coastal environments," he says. "Corrosion can affect combiner boxes, inverters, cables and any other metallic supporting structures. Bird droppings can additionally corrode the glass and frames of the panel, ultimately affecting the performance of the installation – and hence must be cleaned. Aquatic life, such as plants or barnacles, need to be removed from the floating understructure so that they do not weigh down the system."

Michalis Papageorgiou, senior solar engineer at international technical consultancy, DNV GL, takes up the theme on the potential problems caused by aquatic animal and plant life.

"Especially in water bodies with live ecosystems and biodiversity you can't prevent animals from considering the floating solar PV system as part of their aquatic environment, therefore creating

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shelters or just finding it interesting to walk on, causing minor to major issues," he says.

"Tropical reservoirs and dams may have water weeds growing out and also cause shading to the modules. Further to the shading issues, these can also cause mechanical stress on the floating solar PV structure and mooring systems due to increased weight."

Another potential issue highlighted by Papageorgiou concerns the constant moving of the floating PV structure. This causes problems such as mechanical stress at the joints of the rigid structures, on equipotential bonding tapes and DC/AC wires, and at the earthing tape connection for grounding, as well causing stretching or bending of cables, leading to accelerated degradation and cracking and increasing the risk of fire.

But Papageorgiou adds: "Like all PV projects installed in any surface, issues are not inevitable. [It] is well understood that with appropriate PV component specifications from the very beginning, proper system design, standard operation procedures in place and good O&M practices you minimise at least predicted issues for each floating solar PV component and for the floating solar PV system as a whole."

Finance and bankability

Another of the risk categories for floating solar concerns its bankability and attractiveness to financiers. In simple terms, as alluded to by Reindl at the start of this article, a lack of long-term operational data on the performance of floating solar projects means accessing suitable finance is still far from straightforward for the sector, with the consequence that most floating projects are still being financed "on balance sheets". Some exceptions to this appear to exist; for example, the report cites claims from the Chinese inverter manufacturer, Sungrow, which has also become active in floating solar, that despite the slightly lower return on investment from floating projects, banks are willing to support them because they don't "have a real-estate problem" as ground-mount projects do in some regions.

Nevertheless, finance and bankability are still considerable challenges for this nascent segment, and will require a collective effort across the industry to address, starting with ensuring the reliability and durability of the technologies being deployed.

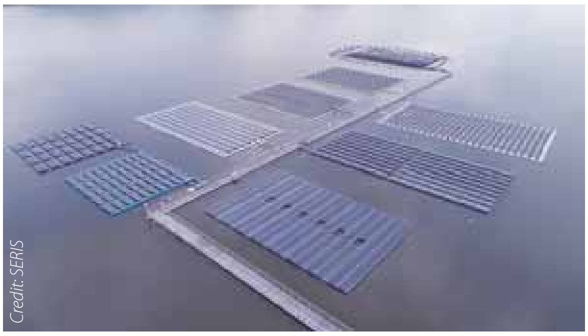
"Reliability equals bankability," says DNV GL's Papageorgiou. "Project financing is the required driver that helps projects to evolve. And project financing from private investors or international financial institutions (IFIs) to owners means that there is a demand from all sides to understand what is the unpredictable in terms of key technical risks.

"In practice we know of course that risks are identified, assessed and managed through key legal, financial and technical review points. Nonetheless, when assessing the investment-worthiness of a floating PV photovoltaic project, different PV stakeholders such as investors, IFIs, insurers and regulatory bodies will evaluate differently the impact and probability of investment risks, depending on their investment goals. Therefore, it is of utmost importance to reduce the risks associated with investments in PV projects. Why? To improve the financeability and attractiveness of these sustainable energy investments. How do we do this? By increasing the trust between the solar industry and investors, IFIs, insurance companies and regulatory bodies. The future of floating PV is still fragile if risks are not predicted and if there is no proven reliability and quality in place."

As with the example of floats explored earlier in this article, the key focus for the industry will be in developing the necessary testing to prove floating solar systems are able to withstand the most likely widely varying environmental conditions they will encounter.

"A site in the tropics may have high humidity and moderately high temperature conditions throughout the year as opposed to another site in Asia where there are sub-zero temperatures where the lake freezes over to minus 20 degrees C," says Papageorgiou. "I believe the floating systems undergoing these stresses will have to evolve to better handle these conditions on water. So there should be clear understanding and tests done to help address this if there is a growing market in these areas."

REC's Sridhara agrees: "I believe the industry plays a crucial role in fulfilling the potential and promise of this segment. Solar panel producers must additionally focus on developing seawater-compliant modules. At the same time, we need reliable and improved understructures to support the installation. In addition, official third-party approval is vital to ensure quality and sustainability: certification protocols and tests should be developed, which address the combination of water quality, module product and floatation understructure."



The testbed on the Tengeh reservoir in Singapore is helping prove the case for new floating solar technologies

The outlook for floating PV

The market potential for floating solar is vast. According to the SERIS/World Bank study, if just 1% of the world's man-made reservoir surfaces were used, global floating solar installations could rapidly reach 400GW – equalling the total installed solar PV capacity worldwide at the end of 2017. Even covering just 10% of every third man-made reservoir in the world would represent potentially a terawatt-scale market opportunity, the report estimates.

The latest indicators certainly point towards rapid growth in the floating solar segment over the coming years, with analysts IHS Markit recently predicting that up to 13GW of new floating capacity will be built by 2023. Whether some of the grander long-term ambitions for floating solar come to fruition remains to be seen.

What is clear, though, is that the underlying drivers for this nascent market segment – rising demand for clean energy, pressures on land – are only going to get stronger as time passes. Floating solar is very much a work in progress, a relatively immature set of technologies that still has much to prove on cost, performance and reliability. But as the growth curve of solar generally over the past decade has demonstrated, this is an industry with an enormous capacity for innovation. Only a fool would bet against floating solar following a similarly rapid upward trajectory, driven by the same spirit of invention that helped propel total solar capacity beyond 500GW last year.

"The solar industry or FPV market does not need any specific help in growing as we have seen the rapid rise in the industry over the last 10 years," says Papageourgiou. "What will continue to drive growth is the competitive cost of solar, ease and simplicity to install generally and the growing need for clean accessible energy. Also where the usual spaces for traditional ground and roof areas become limited then there can be a focus and switch to looking at water bodies to install solar." ■

Bifacial heterojunction PV modules: Highest energy yield available… and how to measure that

Module performance | Recent technology advances and improved industrial processes have made silicon heterojunction one of the most attractive PV technologies, helped by its inherent bifaciality, which offers among the highest levels of bifacial gain available. Researchers from CEA-INES and Eternalsun Spire explore the performance stability and measurement of bifacial heterojunction modules under real life conditions, benchmarking them against PERC modules as the industry workhorse

Silicon heterojunction (SHJ) solar cells have fewer manufacturing steps (five to seven) that are simple to control (regarding homogeneity and defectivity) compared to standard passivated emitter and rear cell (PERC) cells. During recent years, SHJ technology has been rapidly improving on manufacturing readiness with module efficiencies beyond 24%, the availability of high-quality, low-cost thin n-type c-Si wafers, new metallisation and interconnect solutions as well as that of cost-effective mass-production tools for PECVD deposition of amorphous silicon and PVD deposition of transparent conductive oxide (TCO) layers [1]. There are now at least 20 research institutes and pilot or production lines demonstrating efficiencies above 23% as baseline for cells on 6" wafers (see Figure 1). Last but not least, SHJ technology offers cells that are inherently bifacial, with a bifaciality of around 90-95%, whereas PERC cells are limited to 70-80% bifaciality [2].

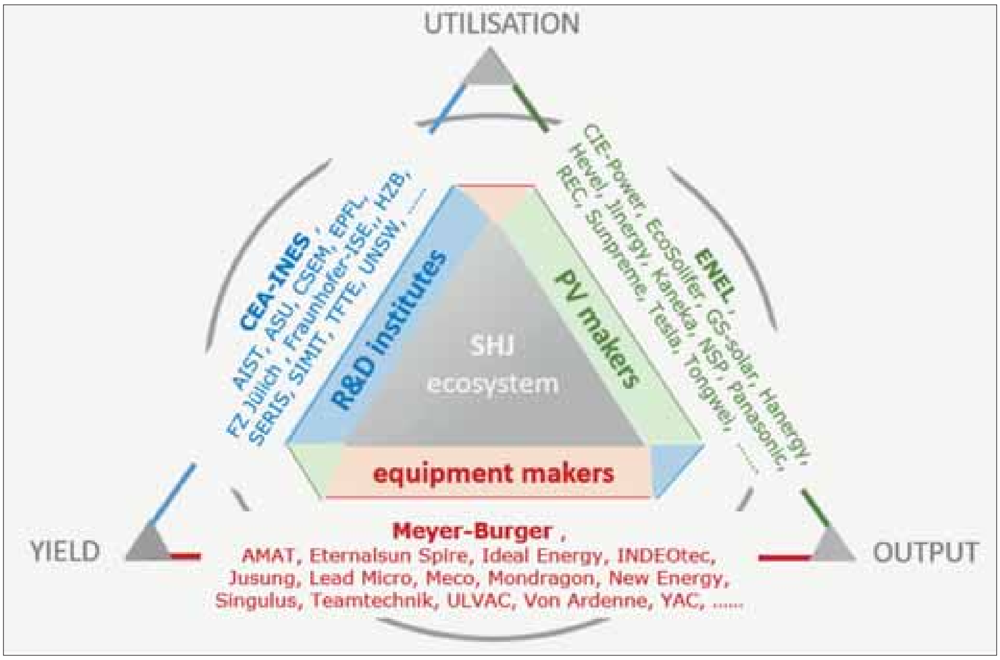


Figure 1. The future of SHJ manufacturing is ecosystem driven

How to accurately measure heterojuncion efficiency

New technologies and efficiencies may require new tools ready to measure them. Traditional short pulse tunnel flash simulators bring a huge offset to SHJ IV-measurements. This is illustrated in Figure 2 and it is due to the capacitive effect inherent in high-efficiency, high V_{oc} PV modules. The outcome of measuring with short pulse tunnel light is that the real power might be overestimated or underestimated, depending on the direction of the IV sweep [3]. Even correction methods such as dynamic IV add an uncertainty of ±0.6 % to the measurement [4], equivalent to ±2.4W in a 400W module.

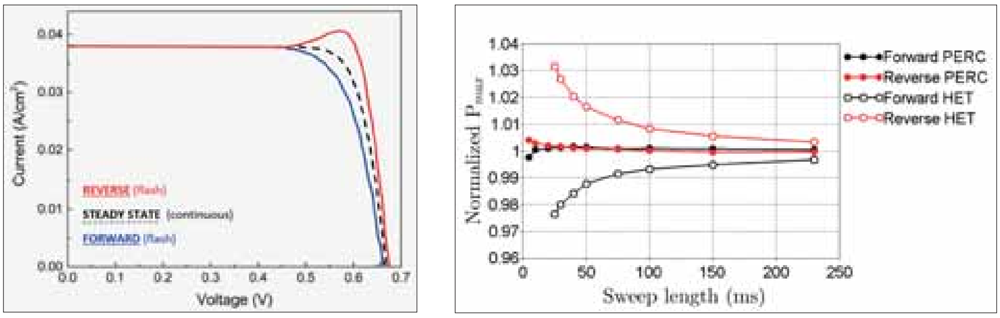


Figure 2. Left: IV curves for forward (blue) and reverse (red) short pulse sweeps compared to a steady-state IV measurement. Right: P_{max} performance measurement for PERC and SHJ modules as a function of pulse length on an Eternalsun Spire long-pulse solar simulator. Measurements converge at pulse lengths above 200ms, not attainable for conventional flash solar simulators

However, the measurement challenges for high-performance (and high-capacitance) SHJ modules can be resolved through the use of long pulse flashes (over 200ms). These long pulses can be obtained with a tabletop solar simulator such as the SPI-SUN 5600 SLP from Eternalsun Spire, shown in Figure 3 and suitable for R&D, certification and manufacturing.

Figure 3. Left: SPI-SUN 5600 SLP table top simulator from Eternalsun Spire. Right: the same setup with an added temperature control box on top, ready for single-sided bifacial measurements

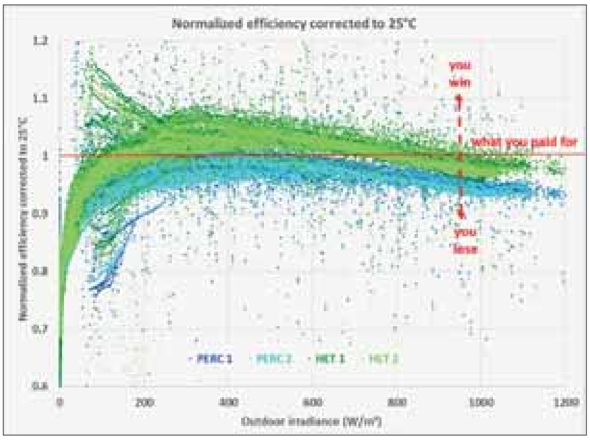


Figure 4. Temperature-corrected module efficiency versus irradiance (in W/m²) obtained outdoor, with one data point per minute taken during one month (April 2018) at the site of CEA-INES in Bourget-du-Lac (France). Two commercial monofacial PERC modules (in blue) are compared to two heterojunction modules (in green) that had been manufactured at the CEA-INES pilot line. The efficiency is normalised relative to the indoor STC efficiency. The financial break-even line is indicated in red, showing SHJ modules to outperform PERC

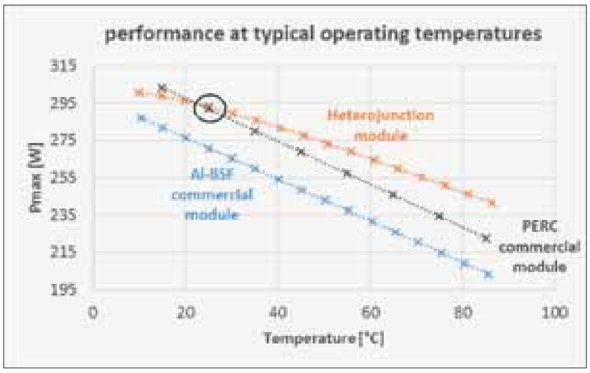


Figure 5. P_{MAX} under one sun versus temperature for SHJ, PERC and Al-BSF modules measured on Eternalsun Spire labflasher with temperature box. The black circle points to the performance of SHJ and PERC at STC conditions (25°C)

Superior performance for SHJ at low irradiance and high temperatures

It is important to know how PV modules perform under lower than the standard STC irradiance of 1,000W/m². Figure 4 shows the results of the outdoor monitoring of PERC modules and SHJ modules over the period of a month at the test site of CEA-INES in Bourget-du-Lac (France). The PERC modules were from a Tier-1 supplier and the SHJ modules were manufactured at the pilot line of CEA-INES in collaboration with Meyer Burger and 3SUN/ENEL. In these outdoor conditions, SHJ technology is seen to give higher efficiencies than PERC over the whole range of irradiance.

The outdoor efficiencies in Figure 4 are normalised to the efficiency measured indoors under STC conditions. This STC efficiency drives the module cost invested in a PV project. So with modules above the red 'break-even' line the project performs financially better than estimated, below this line it performs worse.

The values in Figure 4 have been corrected towards a 25°C operating temperature using the temperature coefficients of the modules. This temperature coefficient is technology dependent and forms a determining factor on the outdoor yield performance. Correct determination of this temperature coefficient is tedious and needs careful procedures and equipment to reduce measurement errors and uncertainties to a minimum. An example of such a temperature coefficient for SHJ, Al-BSF and PERC modules is shown in Figure 5.

Figure 5 shows the performance of SHJ, PERC and Al-BSF modules, measured with the setup shown in Fig. 3 (right). It can be seen that although both PERC and SHJ modules are purchased with a power rating of 295W, SHJ actually delivers 5% more power under realistic temperature operating conditions (>40°C).

Finally, Figure 6 shows the test procedure needed to accurately characterise the power performance under one sun at different temperatures of a PV module of any technology. This procedure can be performed in a setup such as the one in Figure 3 and deliver the results shown in Figure 5.

This SPI-SUN 5600 SLP table top simulator with temperature control box

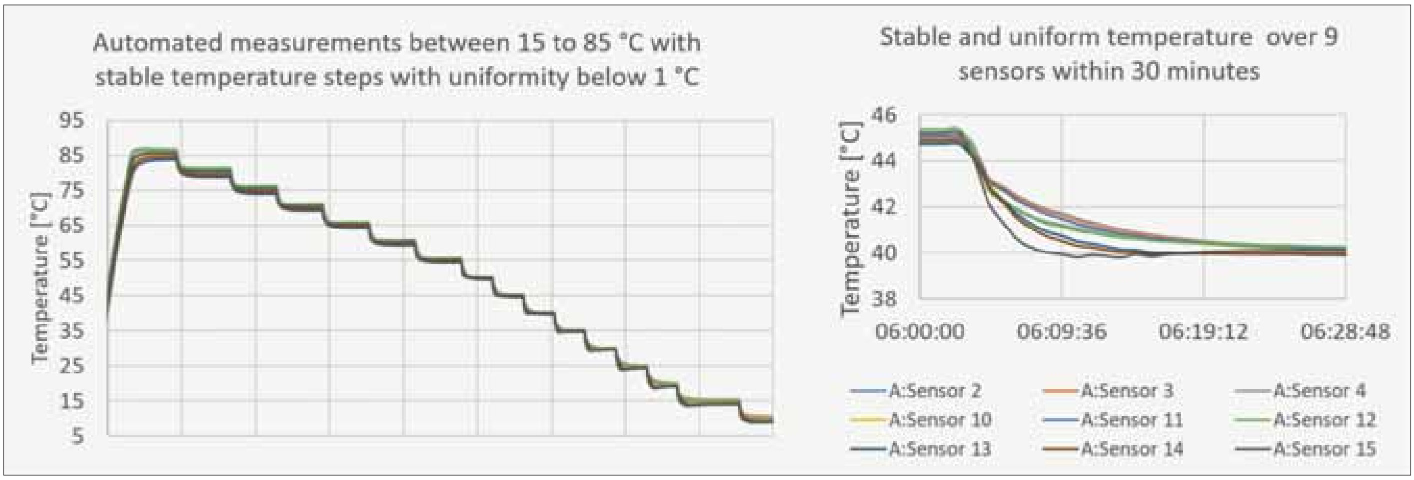


Figure 6. Temperature of the PV module on nine points across the module versus time during the P_{MAX} versus temperature test shown in Figure 5. Note that the temperature is stabilised for accurate P_{MAX} measurements. Test performed on the Eternalsun Spire setup shown in Figure 3

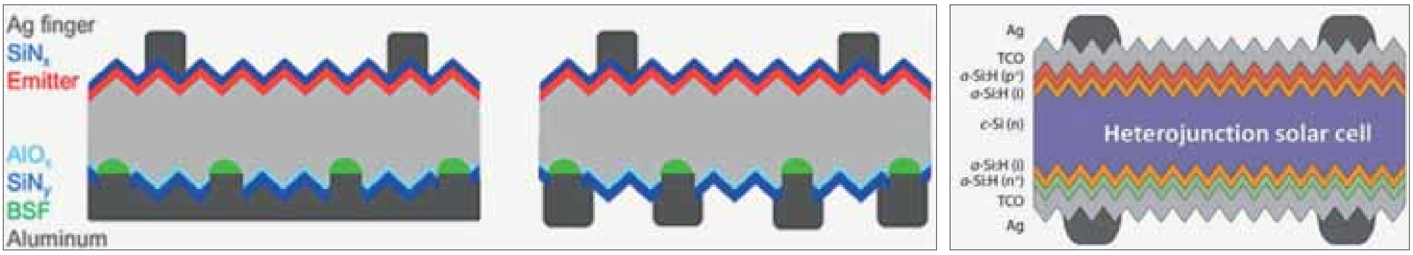


Figure 7. Layout of monofacial PERC (left) and bifacial PERC+ cell (middle) and heterojunction cell (right)

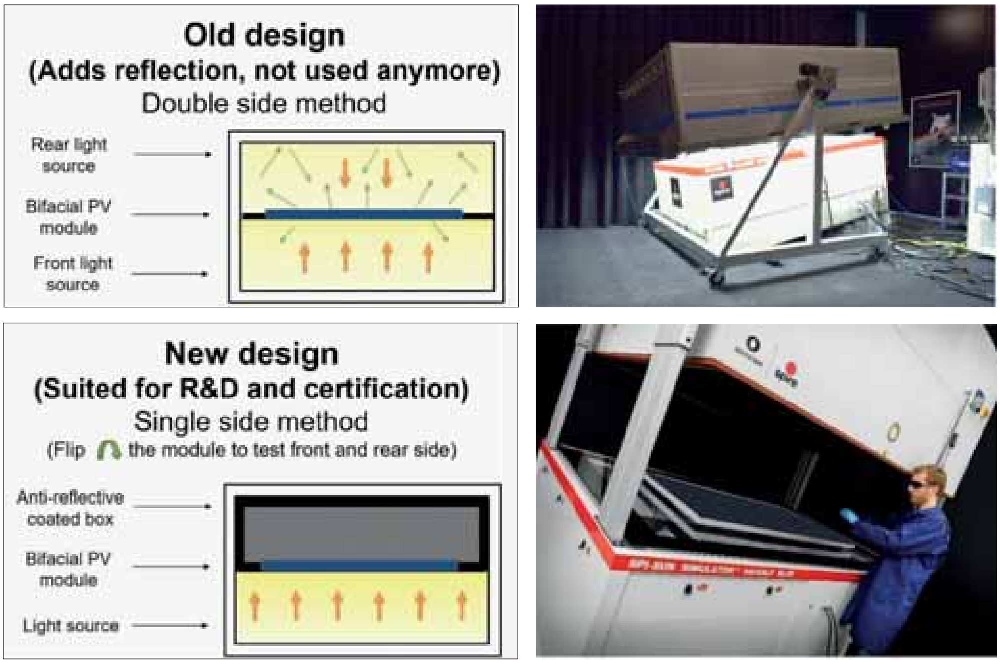


Figure 8. Two bifacial characterisation methods of bifacial with reduced footprint, tested by Eternalsun Spire. The single-side setup is commercially available and already installed around the world

is seen to offer a very good uniformity of the temperature across the module. The IEC standard recommends this spatial uniformity across the module to be below 2°C. The tool exceeds this requirement as it offers temperature uniformity below 1°C, for all temperatures from 10°C to 85°C.

Bifacial benefits and guidelines for low-risk (high-accuracy) predictions

Bifaciality is described as the ratio between power generation of the rear side over the front side when both are under one sun illumination. Whereas bifacial PERC+ cells, as introduced by ISFH [5] hold a 80% bifaciality limit, the heterojunction (SHJ) cell concept has inherent bifaciality (about 95%) thanks to its symmetrical structure, as shown in Figure 7.

Bifaciality of cells and modules may be seen as a straightforward gain offering up to 30% higher energy output due to rear-side albedo and due to opportunities of exploiting new system configurations. An example of the latter is vertical east-west-oriented installations that minimise soiling losses and maximise complementary (agricultural) land usage. A study by Fraunhofer ISE [6] on such a vertical installation has shown that the 20% higher bifaciality of heterojunction modules, compared to PERC, gives them a price margin of 20 or 30% (for a levelised cost of electricity (LCOE) of €0.04 and €0.06/kWh respectively).

To accentuate this energy yield gain, the International Electrotechnical Commission (IEC), in charge of the standards for testing PV modules, has decided to label the performance of bifacial PV modules under three situations. First, under 1,000W/m² on the front side and 0 W/m² irradiating the rear side, secondly, with 1,000W/m2 front and 100 W/m² rear simultaneously, and finally, 1,000W/m² and 200 W/m². This standard is labelled IEC 60904-1-2.

Additionally, the standard also describes two indoor experimental manners of testing the performance of the three situations described above. These two test methods are the double-side method and the single-side method.

The double-side method uses two light sources, which are set at the irradiance levels described in the three situations. On the other hand, the single-side method irradiates both front and rear side separately and afterwards the front side at a higher irradiance, thus compensating for the missing rear irradiance. Note that both methods are approved by IEC for R&D test and certification purposes of bifacial PV modules since they yield the same performance results.

Although it might appear that the double-side method is more realistic, it actually adds complexity to the measurement compared to the single-side

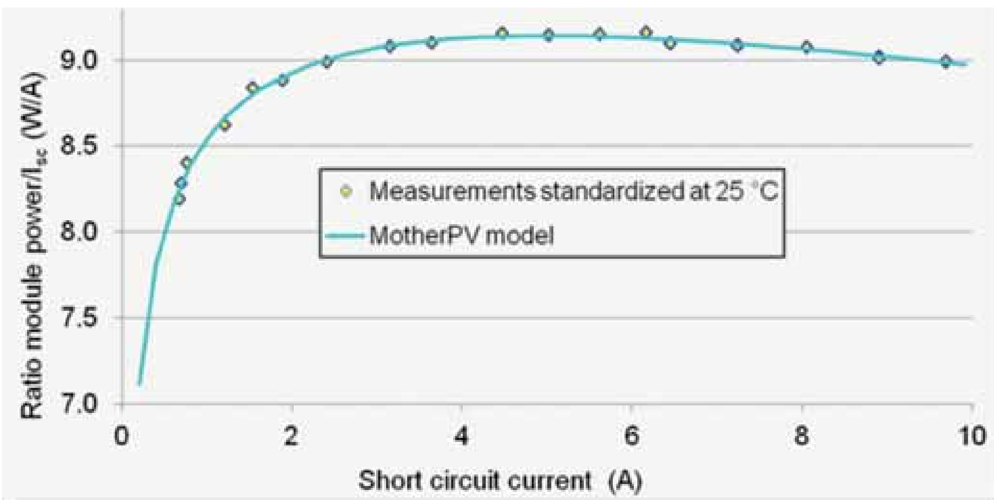


Figure 9. Mother-PV method: measurement and modelling of the ratio of P_{MAX}/I_{sc} versus I_{sc} (at 25°C). Plotted against the short circuit current I_{sc} that serves as a self-reference for irradiance

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method. This is because there are uneven reflections between both light sources, illustrated by green arrows in Figure 8 (top). Note that one of the requests of the IEC 60904-1-2 norm is that there is less than <3W/m2 of reflection, which means 0.3% of 1 sun irradiance. This can be achieved in the single-side method using a hollow chamber with an anti-reflective coating, which reduces reflections to <3 W/m2, as proven and tested by Eternalsun Spire on its Temperature Controlled Laboratory Flasher (TCLF) on the nine locations described by IEC 60904-1-2 and indicated in Figure 6.

To add proof to the single-side bifacial PV testing method, CEA-INES has applied an in-house developed methodology, labelled 'Mother-PV' (**M**eteorogical, **O**ptical and **T**hermal **H**istory for the **E**nergy **R**ating of **P**hoto**V**oltaics) [7,8].

This method measures module performance at different levels of total irradiance around 1,000 W/m2, in this case applied on both sides of a bifacial module, to model the performance at any total (front+back) irradiance level.

The main equation of the methodology is:

$$P_{MAX} = I_{sc} \cdot (A + B.I_{sc} + C.I_{sc}^2 + D.\ln(I_{sc}) + E.\ln^2(I_{sc}))$$

where A, B, C, D and E are the fit parameters of the model.

In conclusion, after applying the method to four different bifacial module types, we found that for a fixed value of the total Isc , bifacial modules behave similar if current is generated on the front- or backside, so without any parasitic or synergetic effects [9].

This conclusion justifies single-sided characterisation of bifacial modules as also proposed in the IEC TS 60904-1-2 test standard, published in March 2019.

Resilience to potential-induced module degradation

Potential-induced degradation is one of the show-stoppers that has been encountered over the last decade of PV plant operation. The problem, basically already reported back in 1978 by JPL [10], emerged in around 2010 due to the increasingly high operating voltage of the modules far above initial values of 600V. It was also aggravated by the increasing popularity, notably in Europe, of more cost-effective transformerless inverters. From a physics perspective, PID stems from the voltage differential between the grounded module frame and the photovoltaic cells near the negative pole of the system using such a transformerless inverter that does not allow grounding.

Figure 10. Climate Chamber Solar Simulator (CCSS), capable of performing accelerated temperature, irradiance and humidity test on modules of different PV technologies

This voltage difference drives mobile sodium ions from the glass to the cells that are accumulated at either the cell junction, causing PID of the shunting type (PID-s), degrading FF and Rsh. When these sodium ions accumulate in the anti-reflection / passivation layer they cause PID of the polarisation type (PID-p), degrading I_{sc} and V_{oc}.

For bifacial modules with glass on the front and rear side the PID problem may concern both the front and backside of the cells. For monofacial PERC cells the PID problem may have been solved for the frontside but once the PERC cells become bifacial their backside, notably the AlOx/SiNx dieletric passivation layer, may become the weak spot as has been recently demonstrated by CSP Halle [11] or SERIS Singapore [12], both showing PID degradation rate from the backside being four times as fast as from the frontside. Whereas the PERC frontside suffers from PID of the shunt type, the backside is degraded by PID of the polarisation type: positive charges are attracted to the AlOX/SiNX stack and eliminate the field effect passivation of the layer stack.

As opposed to the PERC cell structure, the SHJ structure is perfectly symmetrical and instead of dielectric passivation and anti-reflection layers (Al2O3 and SiN) ultra-thin layers of a-Si and ITO are applied. This pays out in a perfect immunity against potential-induced degradation as also reported on commercial HIT modules by Panasonic [13].

Resilience to light- and temperature-induced module degradation

Light- and elevated temperature-induced degradation (LeTID) is a long-term degradation and regeneration phenomenon that can take years to appear in the field. We have evaluated the LeTID mechanism on commercial PERC modules from a Tier 1 supplier and benchmarked them against the SHJ modules developed at CEA-INES in collaboration with Meyer Burger and 3SUN/ENEL.

We have performed studies on the dynamics of LeTID degradation and regeneration using a dedicated climate chamber with integrated AAA sun simulator as commercially available from Eternalsun Spire, shown in Figure 10. This setup can be used to test the reliability, degradation, regeneration and metastability of cells and modules of any PV technology (such as silicon, thin film or perovskite), controlling irradiance, temperature and humidity while doing in-situ IV measurements.

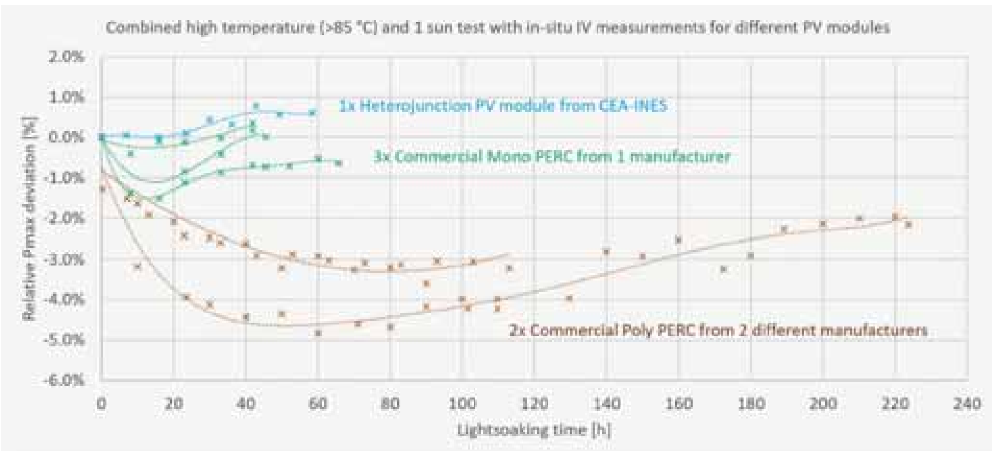

Figure 11. In-situ LETID testing on PERC modules from different manufacturers, showing up to 5% degradation and subsequent regeneration to different extents; and on a heterojunction PV module from CEA-INES, which does not show any degradation but a regeneration of about 1%

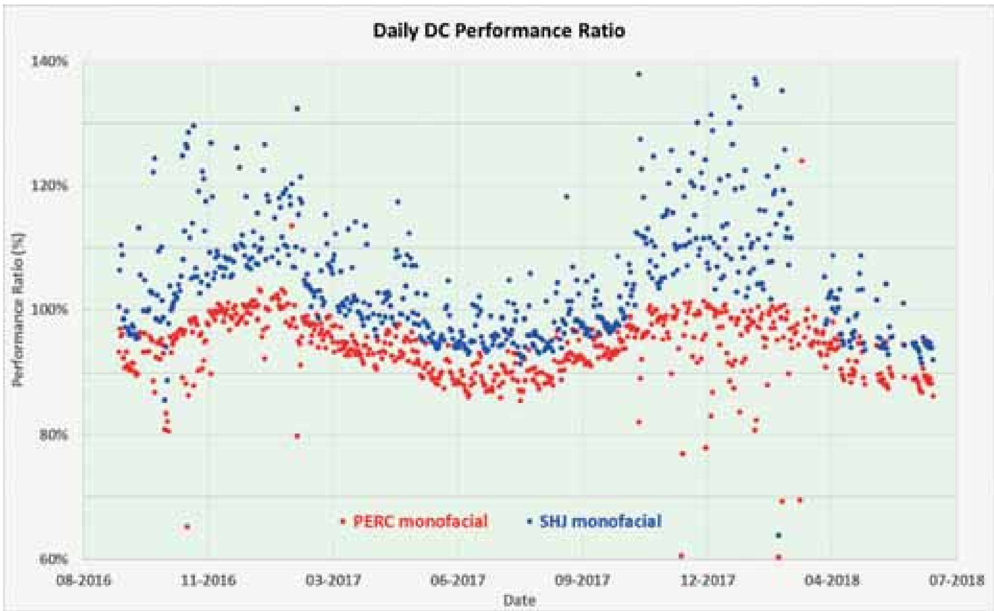

Figure 12. Outdoor monitoring of the average daily system performance ratio over the years 2016-2018 at the site of CEA-INES in Bourget-du-Lac (France). Monofacial PERC modules in red, monofacial SHJ modules in blue

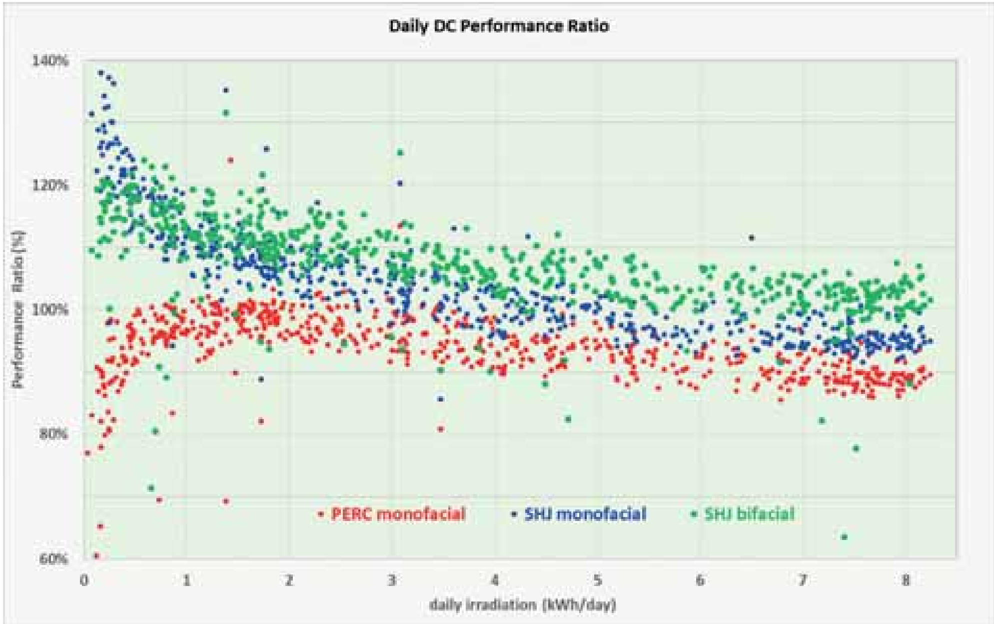

Figure 13. Outdoor monitoring over 2016-2018 of the average daily performance ratio as a function of daily irradiance. Bifacial SHJ system in green

The interest of running such in-situ testing in this dedicated climate chamber is clearly motivated by the dynamic character of the LETID mechanism. If the sun simulator is not integrated, then occasional ex-situ IV measurements are needed, and the major phases of the mechanism, such as the maximum degradation and the onset of regeneration, may easily be missed. The results of testing five different commercially available PERC modules are shown in Figure 11.

In a similar way these LeTID dynamics have been tested on SHJ modules, as also presented in Figure 11. It can be observed that the LeTID test conditions do not provoke a degradation on the SHJ modules but in fact an effective increase of a few percent in module power. The improvement appears strictly related to an increase in V_{oc}, which resembles the reported increase of V_{oc} by light soaking at moderate temperature (32°C) of SHJ modules [14, 15]. This in contrast to the LeTID degradation of PERC modules, which appears as a combined effect of degradation in V_{oc}, I_{sc} and FF.

The inherent resilience of the SHJ technology against LeTID is attributed to favourable hydrogen kinetics (lower saturation and effusion) due to a cell process temperature that is considerably lower (<200°C) compared to PERC (around 800°C) as well as to a-Si:H passivation layers that are much thinner (< 10 nm) compared to the passivation layers of PERC technology. Moreover, the absence of boron in n-type wafer-based SHJ cells helps to eliminate the V_{oc} degradation upon light exposure.

How this all effects the yield in outdoor operation

Figure 12 shows the results of outdoor performance monitoring over a period of two years at the site of CEA-INES in Bourget-du-Lac (see Figure 14) for a system of 10 commercial PERC modules and another system of 10 SHJ modules manufactured on the cell and module pilot lines at CEA-INES.

The graph shows the usual seasonal effect, with a higher performance ratio in winter due to lower than STC temperatures. As the temperature coefficient of SHJ modules is lower than that of PERC modules, the seasonal temperature cannot explain the larger performance offset between SHJ and PERC during winter. To better compare these monitoring data with the outdoor data in Figure 4 we have replotted the results as function of the daily irradiance (in kWh/day). Also we have added a bifacial SHJ module (in green) to the graph.

The results in Figure 13 show that the monofacial SHJ module has on average an 8% higher Performance Ratio than its monofacial PERC counterpart. For the bifacial SHJ module this difference goes up to 14%. Figure 13 also shows the better performance of SHJ modules at low irradiance levels. This then explains the higher offset, observed in figure 12, between PERC and SHJ modules during winter, with more frequent occurrence of low irradiance.

These favourable results for SHJ modules should also be set in the perspective of the annual module degradation rates that have been reported by NREL [16] for heterojunction modules that had been fielded for over 10 years. They reported an annual (linearised) decline of 0.67 ± 0.18% per year, which is statistically similar to an average c-Si based system. They concluded that the degradation was dominated by a decrease in V_{oc} due to an increase of recombination in the cells along with a decrease by a factor of two in minority carrier lifetime.

A similar conclusion was drawn by a two-year outdoor evaluation by TUV Rheinland of SHJ modules in four different climates [17].

Conclusions/outlook

Accelerated indoor tests using in-situ IV characterisation of silicon heterojunction modules showed them to be insensitive to LeTID degradation, as opposed to the commercial PERC modules tested under similar conditions. Similarly no signs of PID degradation were detected for the SHJ modules. The use of a single long-pulse flash is critical for the accurate IV measurement of heterojunction modules. With respect to low-light performance and temperature stability, SHJ modules were found to outperform PERC modules. Finally, a comparison of monofacial SHJ and PERC modules during extended outdoor monitoring showed the SHJ modules to have a superior performance ratio. ■

Figure 14. A partial view of the CEA-INES testsite in Bourget-du-Lac

Acknowledgements

Meyer Burger and 3SUN/ENEL are gratefully acknowledged for joint development efforts, technical discussions and support. The results reported here have been obtained through the collaborative effort of all members of the heterojunction pilot line and PV module platform at CEA-INES. Special thanks to Hervé Colin for managing the outdoor monitoring site at CEA-INES.

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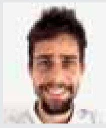

Guillaume Razongles graduated in 2007 from the engineering school 'Telecom Physics' in Strasbourg, France and joined CEA-INES in 2009. There he has been studying the performance of PV modules in outdoor conditions, overviewing the PV market and analysing the LCOE and lifecycle assessment of photovoltaics.

Stefan Roest is co-founder and CTO of Eternalsun Spire, which contributes to the development and growth of the solar industry by enabling the highest accuracy measurements of the efficiency and reliability of PV modules. Stefan Roest is an active member within the IEC TC82 WG2 and is involved in several testing related project teams of PV modules of different technologies.

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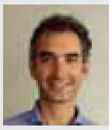

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Presented to you by: Energy Storage NEWS

STORAGE & SMART POWER

114

Introduction

It's funny how contrasting our industry news can be from the mainstream picture sometimes. In the past three months since the last edition of 'Storage & Smart Power' appeared, in *PV Tech Power* Vol.19, our site *Energy-Storage.news* has reported on significant moves across the US, often motivated by utility economics, to deploy or otherwise accommodate energy storage on its networks.

Oklahoma is going to get a giant hybrid wind-solar-storage plant from NextEra Energy Resources, New England's ISO and individual state authorities have opened up opportunities to providers including residential behind-the-meter storage and grid-scale storage for municipal utilities and Utah is about to get a 12.6MWh residential virtual power plant (VPP). You can read about some of the impetus behind the US' drive in my feature article for the main magazine (see p.20).

Ultimately, renewable energy is getting cheaper and cheaper and is making better business sense to utilities than fossil fuels in many cases. Yet if we looked only at headlines in the – I dread to use the expression again but 'mainstream' media – we might only hear about fear of climate change and denial of climate change, rather than ongoing efforts to defeat climate change.

Similarly, don't be fooled if you see headlines blaming renewable energy for a recent, massive blackout in the UK which led to 1 million customers losing power one Friday evening this August. As you'll see from Solar Media's UK editor Liam Stoker's feature article on that blackout (p.114), renewable energy and flexible energy resources including energy storage and demand side response hold many of the answers to the problems of making electricity access fit for purpose in the UK. Many of those lessons will hold true in markets across the world.

Talking of flexibility, it's the key feature of what energy storage can bring to the energy system that is most often missed when we talk about the grid. UK editor Liam Stoker strikes back again (p.118) with some revelations from a recent round table he hosted with some of the country's leading flexibility providers. A clear and present, if not outright urgent need exists for distribution and transmission providers to access the capabilities of battery storage and other flexibility assets and Liam heard from the likes of asset developer AMP, storage developer Zenobe Energy and other stakeholders on the path forwards.

Finally, a fascinating technical case study from Greener Engineering to round off 'Storage & Smart Power' this quarter. Tasked with 'islanding' a section of the Dutch grid, the company used batteries to stand in for the grid in what was dubbed a synchronous grid takeover. Letting households and businesses get on with their day uninterrupted was made possible with a hybrid combination of batteries and a generator. Thanks to Dieter Castelein of Greener Engineering for contributing that one (p.122).

Perhaps we'll see you at Solar & Storage Live in England, or Solar Power International / ESI in the US over the next few weeks and in the meantime, do subscribe to the twice-weekly E-S.n newsletter. Don't forget also that we have a YouTube channel and now a Solar Media podcast while you can also follow E-S.n on twitter: @energystoragenw

Andy Colthorpe
Solar Media

Vanadium redox flow system joins UK's frequency response market

'Flow batteries' could provide frequency response in the UK for the first time ever, as a modestly sized solar-plus-storage system has been pre-qualified into National Grid's dynamic firm frequency response (dFFR) market since late July.

Energy storage technology provider and system integrator RedT - which prefers the description 'flow machines' for its vanadium redox flow, long duration devices - and aggregator / energy data and technology specialist Open Energi achieved pre-qualification status for a 300kWh flow machine installed at an industrial site in Dorset, southern England. The device is coupled with a solar installation with a peak generation capacity of 250kW.

In related news, redT has proposed a 'reverse takeover' with Avalon Battery, in effect a merger, to create a scaled-up global flow energy storage player. You can read in-depth interviews with both parties at Energy-Storage.news.

Credit: redT.

redT's vanadium redox flow in action at a recent project in Australia.

Huge battery system to export cheap solar from South Australia

South Australia's Planning Council has approved a 500MW (AC) solar farm project, co-located with 250MW / 1,000MWh of battery energy storage from renewables developer EPS Energy.

The proposed large utility-scale solar PV plant, Robertstown Solar, will use the batteries to participate in the National Electricity Market, which despite the name spans most, not all, of Australia's national network of grids.

Robertstown Solar alone will constitute 1% of the Federal Government of Australia's target to add 33GW of renewable energy to its networks by next year under its own Renewable Energy Target. It is also expected to create 275 jobs during construction and 15 full-time roles over the operational lifetime of the project. EPS Energy, acting as development manager, said it expects the plant to be operational for 30 years.

Lithium batteries 'more widely recycled' than people think

Lithium-ion batteries are far more widely recycled than many people think, while China and South Korea are already leaders of the emerging circular economy of lithium, a report commissioned by the Swedish Energy Agency has found.

The report's author, consultant Hans Eric Melin, told Energy-Storage.news that many misconceptions and poor observations are made and repeated around lithium recycling. Melin said that more than 70% of lithium-ion batteries recycled today are processed in China and South Korea, with "high" recovery rates of materials.

More than 300 studies of primary research have been conducted worldwide in separating materials in used batteries and re-producing cathode materials or their precursors, 70% of those studies in the two aforementioned Asian battery powerhouses, and finding that "all active materials including lithium can be recycled with high efficiency".

SoftBank puts US$110m bet on Energy Vault

SoftBank's Vision Fund has made its first investment in an energy storage company, betting US$110 million on Swiss start-up Energy Vault.

Energy Vault has developed a form of energy storage inspired by pumped hydropower stations, which rely on the movement of water to store and discharge electricity. In its solution, concrete blocks weighing 35 metric tons are lowered up and down an energy storage tower, storing and releasing energy.

Energy Vault's proprietary cloud-based software autonomously controls the cranes lowering and lifting the blocks. The software relies on a combination of predictive intelligence and algorithms that account for a variety of factors, including supply and demand, grid stability, and weather.

The company was started at California's technology incubator and accelerator program Idealab Studio and launched officially in 2018.

India's 1.2GW tender for dispatchable renewables

The state enterprise Solar Energy Corporation of India (SECI) issued at the beginning of August a tender for 1,200MW of renewable power that can be used to alleviate peak demand issued on the grid, in effect mandating the use of energy storage systems (ESS).

An invitation has been issued for bids to build, own and operate renewable generating facilities and enter into 25-year power purchase agreements (PPAs).

Solar and wind (or combined or hybrid systems) must be capable of dispatching power to the grid for at least six hours each day. Off-peak energy will be provided a flat tariff payment of Rs. 2.70/kWh (US$0.038), while a separate peak tariff will be determined through 'e-Reverse Auction', the SECI invitation document said.

Korea's ESS fires: Batteries not to blame

After fires were started at a reported 23 battery energy storage installations in South Korea during 2018, the country's Ministry of Trade, Industry and Energy, and the national Standards Committee held a press briefing in June, revealing that in nearly every case the issue appears to have been poor management of batteries, rather than anything inherently unsafe in the batteries themselves.

According to local press, defective battery cells were not found to be the cause but instead electric shocks caused by faulty battery management, system control or battery protection systems and faulty installation practises.

Blackouts and batteries: how storage saved the UK grid

Grid | At 4:52pm on Friday 9 August 2019, the UK suffered its first wide-scale blackout in over a decade. More than 1.1 million consumers were plunged into the dark as rail lines screeched to a halt, traffic lights failed and even airports reported problems. Liam Stoker looks at the root causes, and how battery storage came to the rescue

Credit: National Grid

16:52:33.490. Those nine consecutive digits won't mean much outside of the UK's energy sector, but they're likely to be etched into folklore. It's the precise timestamp for when, on 9 August 2019, a single lightning strike sparked a cascade of events that caused the UK's first major blackout in over a decade.

More than one million people experienced power outages and widespread disruption, with not insignificant swathes of the country's rail network taken out of action, albeit temporarily. The incident made national headlines for days after, as theory and rumour abounded.

A cyber attack? No, the UK's transmission system operator National Grid quickly dismissed. Were renewables to blame? Earlier that day wind had provided more than half of the country's power, a feat which had the renewables lobby celebrating. That just hours later the lights had gone out was a fact not lost on a number of climate change sceptics.

But those theories were also dismissed by National Grid in the days after the event. While there was indeed marginally less inertia on the grid that day, courtesy of less synchronous generation, this was not something that ultimately contributed to the blackout.

The true cause, according to National Grid's preliminary investigation, released on 19 August, was perhaps both simpler and more complicated at the same time.

The UK's power blackout on 9 August highlighted the importance of batteries to the grid's stability

Thunderbolts and lightning

National Grid's timeline puts together a sequence of events that while individually manageable, together caused a drop in frequency sizeable enough to cause the blackout. Lightning struck a transmission circuit near Eaton Socon, a town in Cambridgeshire.

That lightning strike, as tens of others that hit grid infrastructure that day, was said by National Grid to have been dealt with by its protections systems normally. It did, however, trigger a Loss of Mains protocol that took around 500MW of embedded generation – domestic solar panels, batteries and the like – off the system. That loss of generation would prove pivotal.

The blackout timeline

16:52:33.490 National Grid Electricity Transmission (NGET) reports a phase to earth fault at the Eaton Socon - Wymondley circuit, caused by a lightning strike.

16:52:33.728 Orsted's Hornsea offshore wind farm starts to deload its generating capacity, having generated 799MW milliseconds before.

16:52:34 A steam turbine trips at Little Barford, taking 244MW off the system.

16:52:34 National Grid Electricity System Operator (ESO) initiates its frequency response in a bid to stabilise the grid frequency having seen it drop to 49.1Hz.

16:53:18 The ESO reports that frequency response recovers to 49.2Hz, stemming the downward curve.

16:53:31 Further units at Little Barford trip, meanwhile all of National Grid's frequency response units are being delivered in an attempt to restore the frequency.

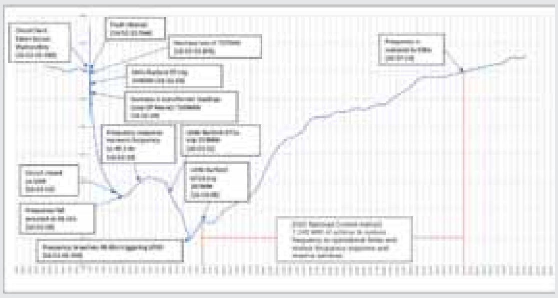
16:53:49.398 Grid frequency dips again, breaching the operationally safe 48.8Hz limit. Distribution network operators trigger LFDD protocols and disconnect 931MW of demand from the system.

16:53:58 A further unit at Little Barford trips, complicating matters further. At this point, the cumulative infeed loss caps out at 1,878MW, totalling 1,378MW of transmission system-connected generation and ~500MW of embedded generation.

16:57:15 Frequency returns to 50Hz after 1GW of DNO response and 1,240MW of control room actions taken by the ESO.

17:06 DNOs are told they can begin to restore demand to consumers.

17:37 All DNOs confirm that demand restoration is complete.



How the grid's frequency dropped and was restored on 9 August

Seconds later, within a few miles of the lightning strike, a CCGT power station, named Little Barford and owned by European power giant RWE, came offline, taking around 700MW of generation with it. Within seconds of that occurring, Orsted's Hornsea offshore wind farm also came offline, contributing to an event National Grid described as "rare and unusual".

The reasons for two sizeable generators coming offline at once are the subject of continuing investigations. National Grid said it wanted to collaborate with both RWE and Orsted to better understand the respective power stations' failure mechanisms, and both operators have remained fairly tight-lipped to date. What the system operator was almost immediately prepared to dismiss however was a previously held theory that the incidents were somehow connected to each other, or that a failure at one plant triggered a failure at the other.

49.5 - 50.5Hz
The safe operating transmission system frequency National Grid is obliged to maintain.

Altogether, around 1,378MW of generation came off the UK's transmission system within mere seconds, plunging grid frequency to an initial low of 49.1Hz, followed by a secondary dip which took frequency to 48.8Hz, far outside the safe operating limit. Attempts to use reserve capacity to restore the frequency failed, meaning that National Grid was forced to call on the UK's regionalised distribution network operators to begin Low Frequency Demand Disconnection (LFDD); essentially switching customers' power supply off.

Customers were left in the dark, but battery storage operators – 475MW worth, according to National Grid – stormed into action.

Batteries and bounces

Milliseconds after Little Barford came offline, National Grid signalled its reserve capacity to help offset the collapse. Batteries began to discharge and other generators sparked into life and, for a fleeting moment, it looked as if the worst had been averted. Hornsea's fault, however, sent frequency falling again and National Grid's reserve was insufficient.

National Grid has since clarified that its capacity reserves stand at around 1GW – the minimum amount approved under its Security and Quality of Supply Standards. This figure is designed to offset the collapse of its single largest generator of power, currently the 1.2GW Sizewell B nuclear reactor.

Losing closer to 1.4GW in seconds is an event, or rather a collection of separate, individual events, that was evidently something for which National Grid was not prepared. Whether or not the system operator should have a more significant reserve to dip into, especially as greater quantities of non-synchronous, renewable power comes onto the system, is something which is likely to end up a central element of forthcoming debates.

Nevertheless, battery storage operators discharged and other generators continued to chip away at the grid's shortfall. As DNOs began to take up to 1GW of demand off the system – the actual, technical cause of customers experiencing blackouts – grid frequency began to return to normal.

It took just two minutes and 22 seconds for that combination of load shedding and frequency response – a not inconsiderable amount provided by batteries – to restore the frequency to safe levels, four-time faster than the last time such an incident occurred in 2008. Within four minutes – 3:47 to be precise – grid frequency had been restored to its usual operating limits, significantly quicker than the 11 minutes it took a decade ago.

The incident was made all the more interesting from an operational perspective when LFDD protocols kicked in. National Grid had already instructed flexible assets to discharge in a bid to make up for the lost capacity, but the moment DNOs started shedding load, National Grid quickly felt a bounce in the frequency and batteries were just as quickly instructed to respond. "When National Grid cut off the power, the frequency bounced back very quickly, sending the system the other way and meaning our battery sites were then called on to balance the grid by taking power out," Anesco asset management director Mike Ryan said.

Within four minutes, the UK's electricity system – widely regarded as one of the most secure in the world – tripped, recovered and was restored to within safe operational limits. Batteries played a pivotal role, but the fact the system tripped altogether has been an event contentious enough to trigger two separate official investigations.

Could more batteries have been used to greater effect?

What the future holds

Limejump chief executive Erik Nygard has called for a significant increase in firm frequency response (FFR) styled products which can procure the kind of fast-acting response necessary to offset such sharp drops in grid frequency.

National Grid's 200MW-strong portfolio of enhanced frequency response (EFR)

Credit: Vattenfall

Grid-scale battery storage is experiencing a boom in the UK

batteries, which respond to frequency events in 0.5 seconds, did indeed help the system operator's response, but a drop off in the rate of FFR procurement in 2017 has meant that fewer batteries and less DSR – the kind of non-synchronous generation that's vital during periods of low inertia – are being supported.

Nygard says that National Grid could effectively double its FFR-ready fleet, possibly mitigating for circumstances like Friday 9 August, at a cost of around £100 million per year. Given that cost would effectively be passed onto consumers via levies, and how sensitive a subject energy bills have become in the UK, what equates to roughly a few pounds extra per year could be a small price to pay for energy security.

Jonathan Ainley, head of public affairs and UK programme manager at KiWi Power, meanwhile, has said that National Grid must do more to open up the Balancing Mechanism (BM) to more significant quantities of distributed generation, arguing that it is currently "dominated" by large-scale, centralised generators of a dirtier heritage.

Indeed, the UK is experiencing a grid-scale battery boom at present. The aforementioned 200MW of EFR-backed batteries provided the industry a stable base to build upon, and developers and financiers alike are now driving a not insignificant amount of activity. *PV Tech Power* publisher Solar Media's in-house market research team has previously guided that as much as 500MW of utility-scale battery storage could be built this year alone, and that's without even considering the nascent C&I and residential markets.

The areas impacting battery storage and its ability to help the UK's grid security lie elsewhere. While it's true that National Grid's distributed energy resource (DER) desk – set up by the energy system operator last year to help operators of smaller, more flexible assets gain access to new markets – has led to a boon in the DER capacity bidding into such markets, some rather sizeable barriers to entry remain, chiefly the need for an energy supply licence, which is a particularly prohibitive obstacle for smaller companies.

"With the right markets, flexibility providers can rapidly bring forward fast-acting, flexible capacity to help National Grid avoid a repeat of [August's blackout] and create a smarter, cleaner, more resilient energy system for everyone," Ainley said.

Meanwhile, there's also the not-insignificant problem created by inertia, or indeed the lack of it. Friday 9 August witnessed considerable wind generation and, having produced as much as 50% earlier in the day, the UK's wind fleet was providing around 33% at the time of the frequency event. As a result, the amount of inertia on the system is expected to have been low.

Inertia's role on the system and whether or not it had much of an impact on the events of that day have appeared to divide opinion in the energy sector so far, and will inevitably be a line of inquiry in both Ofgem and the BEIS' investigations. Nygard says the UK would do well to create a system which produced more inertia as non-synchronous generation grows, either by adding more batteries and DSR or synthetically by forcing such generators to do so via their inverters.

Tinkering with the energy market itself may also elicit a response. Given the entire incident took just under four minutes from trip to recovery, energy markets – which trade in 30-minute settlement periods – were all but unaware of what was happening and unless they were actively looking, traders would have been none the wiser. Bringing those markets to settle more frequently – a technical challenge, but not an impossibility – may have allowed price signals to act as the first canary down the mine so to speak, and the market could have responded in kind.

The incident itself, while perhaps alarming at the time, has arguably demonstrated the efficacy of National Grid's systems and protocols. If it weren't for the "rare and unusual" event of ~1.4GW of capacity collapsing in seconds, consumers would have been none the wiser. What is evident is that grid security is fragile and the margin at which National Grid operates is perhaps no longer fit for a system changing at rapid pace.

National Grid's interim report has provided a skeleton that will inevitably be fleshed out when the final report is published in mid-September. Alternative investigations, led by both Ofgem and the government's official Energy Emergencies Executive Committee (E3C), will establish if any of the parties involved were at fault and, if they were, fines are likely to be issued. National Grid itself could be fined as much as 10% of its annual turnover if it is found to have breached its licence conditions.

The chapters in the final report crucial to the sector will lie somewhere towards the back. Those will establish not just recommendations to prevent similar events from happening in the future, but a timeline for those to be enacted. Flexibility providers consider it highly likely that National Grid's reserve capacity will simply have to increase in the wake of 9 August 2019, something which could see more batteries land reserve contracts and, thus, become bankable.

Battery storage came to the UK's rescue on 9 August 2019, demonstrating – as if it was needed – the role the asset class has to play in grid stability. In the aftermath of that event, that role only looks like increasing. ■

Flex and flexibility

Grids | Power markets are evolving and beginning to value flexibility ahead of generation. As the UK's networks companies move to embrace flexible generation assets, Liam Stoker spoke to some of the country's leading providers to identify the hurdles and solutions to a more flexible power grid

Credit: Getty Images

The UK's power sector is evolving at such a rate that generators, grid operators and utilities alike can scarcely believe the pace of change. It seems a new renewable energy record tumbles each week, with coal falling off the grid for large parts of the year already.

While this is unquestionably good news, it's left the country's transmission and distribution network operators (DNOs) in something of a quandary. There is now a clear and present – and some might add urgent – need for far greater quantities of flexible generation to both balance the grid and offset the need for more costly reinforcement works. A power market that once valued generation above everything now considers flexibility worth its weight in gold or, indeed, lithium-ion.

The networks have been proactive in this regard, and have taken to sourcing their own flexibility. Localised tenders have been introduced, helping connect with owners and operators of flexible assets to ease distribution-level grid constraints. Having tentatively explored the market for such auctions in 2018, DNOs are now transferring flexibility markets into business-as-usual activities, and using them to future-proof large sections of the grid.

But in some locations, the market appears at an impasse. Flexibility is a resource in demand, but providers are either shying away from tenders or simply do not have the projects required, nor the economic business case to build.

In order to address this shortfall, *PV Tech Power* sister publication *Current±* collaborated with the UK's Energy Networks Association and assembled 16 of the UK's leading flexibility providers, aggregators, asset optimisers and energy technology firms to determine precisely what hurdles the flexibility market still faced and, crucially, how the sector could overcome them.

The UK's power network is beginning to value flexibility over generation

A transparent need

One of the significant hurdles raised by market operators spoken to was a distinct lack of necessary data and transparency on the part of the DNOs. At present, data that is shared with the market pertaining to possible areas of curtailment is limited to where the congested areas are today, and is given in broader times.

That, a number of companies said, simply wasn't good enough for them to be able to build a business case robust enough to stand up a new battery storage project or other generating assets. "Data is absolutely key," said Mark Tarry, chief financial officer at asset developer AMP, adding that network operator's Long Term Development Statements – which formally document areas of works – are limited in their scope to areas of constraint today. "What you can't do is try and estimate where the areas of constraint will be in two, three or five years' time, and that is what is important," Tarry said.

This is significant for project lead times, particularly if there is any involvement from a community energy group or other party such as a landowner, as is frequently the case in the UK power sector. Identifying an appropriate site, conducting due diligence, negotiating lease fees, agreeing contract terms, building a bankable business case, pursuing and sealing planning permission, gaining a grid connection agreement, and all the associated procurement, engineering and construction works mean it can be years before a project can get off the ground. Jo-Jo Hubbard, founder at blockchain specialist Electron, concluded that time remained amongst the biggest challenges across the board for small-scale flexibility assets. It's evident that even the most nimble and expedient of project developers cannot move fast enough for the status quo.

Better data is needed to identify network constraints where, for example, battery projects would help ease congestion

Credit: Zenobe Energy

James Basden, founder and director at battery storage developer Zenobe, echoed Tarry's sentiments, commenting that transparency surrounding data, particularly those relating to networks and areas of constraint, needed to be drastically improved.

"If we can see what the potential is to get in and put new flexibility assets on [to the grid], whether there is a rate of return that's acceptable… looking at how different technologies could be a better solution than conventional grid reinforcement, it's something that could be really very interesting… but it's almost impossible get hold of that data," Basden said.

And when that data is forthcoming, it might not even be particularly useful. Tarry spoke of a time when he was shown constraint information – essentially the projected load versus the capacity – of a particular substation in the UK. In order to forecast how that load may develop over time, the DNO in question had applied a generic growth rate of 1%, something it had applied universally across its licensed network.

That substation was already at 80% of its capacity, but what the DNO had failed to factor into its forecasting was that, next door, a new business park was to be built under the premise of creating 15,000 jobs. Not only that, but a considerable factor of that development's sustainability credentials was the addition of electric vehicle chargers, contributing to what would have been a sizeable addition to the load on that substation. That information had been in the public domain, and could have been used intelligently by the DNO to create a more accurate, forward-looking picture of future constraint.

The solution, according to our panel, is for the DNOs to ramp up their efforts when it comes to data and transparency. If the network operator can forecast constraint zones two to five years in the future, then these forecasts should be forthcoming to take into account the inevitable lag in project lead times.

Furthermore, the data provided needs to be far more granular than is currently on the table. If such constraint data was to be made available on a substation-by-substation basis, then project developers would be able to pinpoint precisely the areas of need, and target their services more accurately than is currently the case.

This point becomes all the more salient when network charges are taken into account, and how this level of granularity could be adopted into the densely complicated area which is network charging, and used to great effect.

Charging forward

The UK's network infrastructure is essentially owned by monopolies regulated by the country's regulator Ofgem, meaning that their respective revenues are tightly controlled. This is achieved through network charging, which is essentially a cost levied against generators and suppliers in order to transmit and distribute power via the country's cables and lines. These charges are many and complex, and subject to a significant ongoing review.

The aforementioned Ofgem is facing a quandary; how to evolve those charges alongside a changing energy system, while maintaining their impartiality and equality. It's something the energy sector remains split on, and Ofgem has been on the end of some stern criticism surrounding recent proposals that the flexibility industry has warned could render large numbers of projects uneconomical.

The panel of flexibility providers assembled was unequivocal that uncertainty stemming from Ofgem's charging reviews had hindered flexibility projects coming forward, but were equally certain that, with a few minor tweaks, they could be used as a signal within areas of constraint that flexibility projects, and services, are needed.

These tweaks divided the room, representing the difficult nature of Ofgem's job. Conor Maher-McWilliams, head of flexibility at Kaluza, which is part of the OVO Group, said that price signals could be broadcast through network charging opportunities – essentially making it cheaper to operate a flexible generation asset than it might otherwise have been – pre-empting an overloaded substation and direct procurement.

Network charges could stand to be an ideal way of incentivising flexibility asset development and indeed targeting it, but nothing does the trick quite like a market auction, as the network operators have already established.

Markets and contracts

When it comes to how best to procure flexibility, timing once again rears its head. Melanie Ellis, head of regulatory affairs at aggregator Limejump, said that it was critical that project lead times are taken into account when tendering for services. There's no point tendering for flexibility for six months' time in an area where there's little existing flexible generation, for example.

It's also critical that the contract lengths on offer remain diverse. Long-term contracts are perfect if projects need financing – nothing quite sates a financier like multiple years of predictable revenues – but locking a sizeable battery, for example, into four years of having to be available during peak times, when revenues and values may well shift elsewhere, could dissuade operators from taking the plunge. Claire Addison, head of regulation at Flexitricity, said there was a "spectrum of views" when it came to contract lengths.

Handing out lengthy contracts can also negatively impact market liquidity. Locking in sizeable contracts for years at a time could limit availability in future years and, as a result, prevent new projects from coming forward.

There is also something of a split between what asset owners want and what DNOs need. Owners, as Hubbard says, need to be able to have explicit, concrete guarantees that they can provide flexibility in return for revenues and if there are non-delivery penalties, then a clear idea of what those are precisely. Network operators on the other hand simply need to know that there's enough flexibility on the network in the near future to balance should the need arise.

Given the considerations at hand, the network operators face a Goldilocks-esque dilemma when it comes to procuring flexibility. One such possibility mooted by the panel would require more of the previously highlighted transparency, but would exhibit the direct value flexible generators can provide. If, for instance, a network was considering traditional reinforcement works, said network could publish its cost expectations and the additional capacity to be delivered, and invite flexibility providers to compete against those parameters. Basden was convinced that in doing so, it would be "fairly rare to find a case where the battery doesn't outperform the reinforcement".

If the data were more granular, network charging reformed to send the initial signal and the products designed in the correct way, then all that's left is to properly engage, both with flexibility providers, communities and consumers.

But even that isn't as straight forward as it may first appear.

Prior engagements

There is a stated desire for community energy groups to be brought into the fold when flexibility is procured, given their inherent engagement with the very communities the DNOs serve. These are often made up of likeminded individuals who have a passion for renewable electricity, but not necessarily the expertise to see a project through. As a result, these groups are likely to need a broader spectrum of support, be it financial, legal or technical, when it comes to bidding into flexibility markets.

There needs to be a greater degree of "hand holding" in the early stages of project development, Flexitricity's Claire Addison said, which could take the form of a series of case studies or successful project examples. That way, rather than having to navigate the complicated UK energy market on their own, community groups could assess which project or case study more closely resembles their own and simply follow a (hopefully) well-trodden path.

Then it becomes a case of engaging with perhaps the least engaged party of all: the consumer.

The UK power market isn't exactly famed for its consumer-centric approach. Since it was privatised in the 1990s, the energy retail space in the UK has treated consumers more like assets than valued customers, much to the chagrin of consumer groups and politicians alike. A cap on what energy companies could charge customers on standard tariffs, enacted at the start of 2019, has only served to complicate relations further.

But there are signs of hope on the horizon. A number of trials which involve bringing consumers into demand-side response markets have been successful, and energy companies are now waking up to the inherent value of having hundreds of thousands of informed and engaged customers.

Maher-McWilliams, whose parent company could be about to become the UK's second-largest energy supplier, is vocal in his support of equipping consumers with all they need to enter such markets – both hardware and otherwise – and then ensuring that the benefits are shared with them.

It would appear that while it's the DNOs that ultimately need the flexibility, and indeed should bear some responsibility in consumer engagement and education, the relationship ultimately lies with the provider of energy. The DNOs should therefore be more concerned with ensuring the market framework is correct, enabling their participation in the first place.

"We as aggregators need to work out ways of sharing the benefits with domestic consumers by letting them know up front what those benefits might be," Addison said, adding that it's not just those that are presently engaged that need convincing. "Early adopters aren't going to tip the dial and you need engagement with a broader spectrum of customers, and much more concrete ways of sharing the financial benefit."

Flexibility is a nascent market for the UK power sector, so enamoured as it has been with generation, to consider. But it is nevertheless coming to terms with the new energy paradigm and flexibility markets are opening up across the country, from the Shetland Isles in the north to Cornwall's south coast.

There are undoubtedly lessons to learn and regulations to be tweaked, but this is a sector that's as much as a learning curve for network operators and regulators alike. If these adjustments can be made, flexibility could be on the cusp of a transformative boom. ■

The GenGame example

Over the course of two years, more than 2,000 of Northern Powergrid's customers in the north east of the country shaved an average of 11% off their electricity consumption simply, principally by playing a game developed by gamification firm GenGame.

Downloaded to mobile devices via Facebook, the game communicated with devices installed in homes which monitored consumption. During periods of high demand on the grid, GenGame prompted players to reduce their consumption in return for points, which were used each month in order to increase their chances of winning portions of a £350 cash prize.

Northern Powergrid assessed the responses, and found that while the average customer turned down to the effect of 305W, some consumers managed to switch off as much as 4.9kW by switching off their EV chargers, for example.

The premise behind the game is simple, according to GenGame chief executive Stephane Lee-Favier. A consumer might only save 10p by turning their washing machine on at a less convenient time, but if doing so could help them win as much as £100, then that stands to be far more successful at incentivising behavioural change.

Credit: Northern Power Grid

GenGame is helping customers save money on power bills

Using batteries to reduce the impact of grid maintenance

Storage applications | Batteries are increasingly widely used in grid balancing, but there are many more applications where a battery can play an important role. With electric grids requiring periodic maintenance, batteries can stand in for the grid during downtime in order to reduce the impact on industry and households, writes Dieter Castelein

We consume more and more electricity every day. The utilities and grid distribution operators must ensure industry and households are provided with the necessary connections. In order to do that, the grid must be expanded, and must be maintained periodically. This means that more often the power on the grid will be cut off while the necessary works are undertaken.

How is this currently done?

Today, when the grid is being maintained, the power is cut off at the transformer where the maintenance is done.

Nowadays, it is not possible to do any business or run a household without having power available; that is why during this time of maintainance, a solution has to be found to keeping the lights on.

It's all about efficiency

Traditionally, the energy demand for these periods has been met by diesel-fuelled generators. To absorb the peak demands of the grid and to prevent power loss, an oversized setup of generators is used to guarantee a consistent flow of energy.

Research from multiple festivals, where a lot of diesel generators are used, show that the average load was 12%, while the generators are the most efficient between 60% and 80% of their maximum engine power output. See Figure 1 for the energy data of a four-day festival and the average power output of the diesel generator.

The inefficient use of generators means that a great deal of diesel is being burned unnecessarily. These emissions contribute to climate change and poor air quality in cities.

Moreover, we see that more and more buildings have solar panels on their rooftops. A diesel generator cannot cope with current coming back on its output

Battery systems can play an important role in providing grid continuity during maintenance periods

Credit: Greener power solutions

side. This means that when the load on the grid is smaller than what the solar panels in this area are producing, this energy has to be (quite literally) burnt away in big heaters. Which naturally is, again, a waste of energy and is not helping in our efforts to tackle climate change.

Also, these diesel generators produce quite some noise. This can be irritating to inhabitants when this solution is applied next to their bedroom.

Can batteries be a solutions during these grid take-overs?

Batteries can provide a solution to a couple of the challenges that are faced during these grid take-overs, but also have a challenge of their own. When applying a battery in this situation, you can only use as many kWhs as the batteries you bring to the site. When the battery has 0% charge left, it cannot fill itself anymore. With a generator on the other hand, you could just fill up the diesel again and start it back up.

That is why the best possible combination is a hybrid system. The benefits of the hybrid system are:

1. A significant saving in fuel consumption;
2. Reduction in CO2 emissions by using

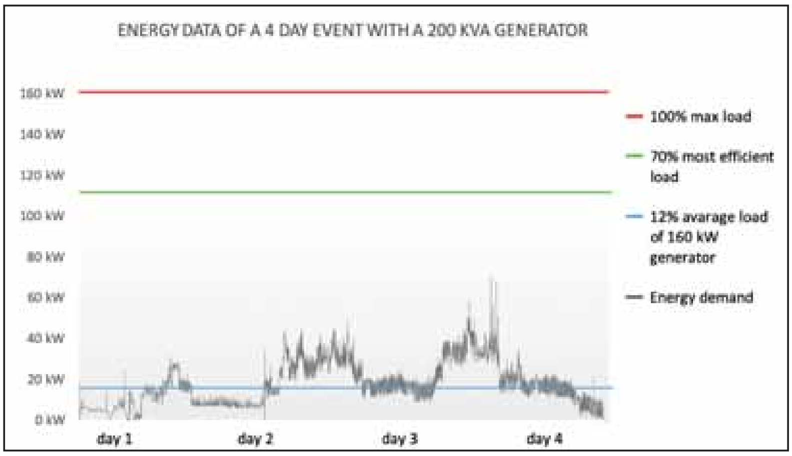


Figure 1. Energy data of a four-day event with a 200kva generator

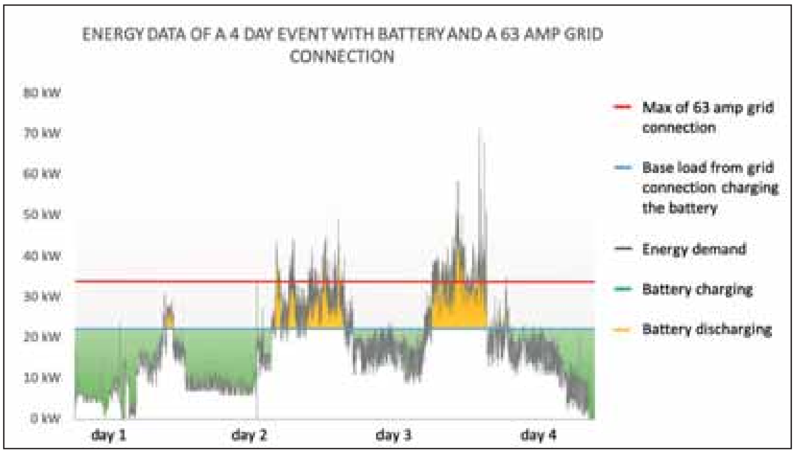
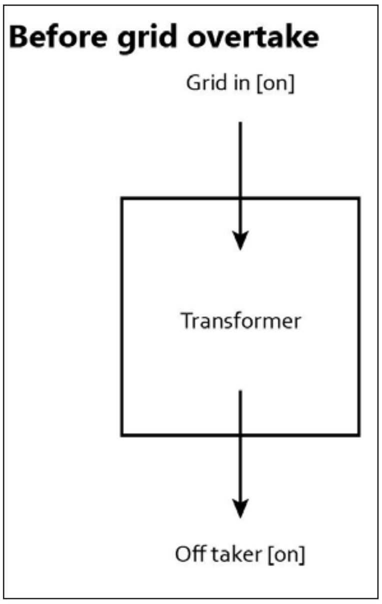
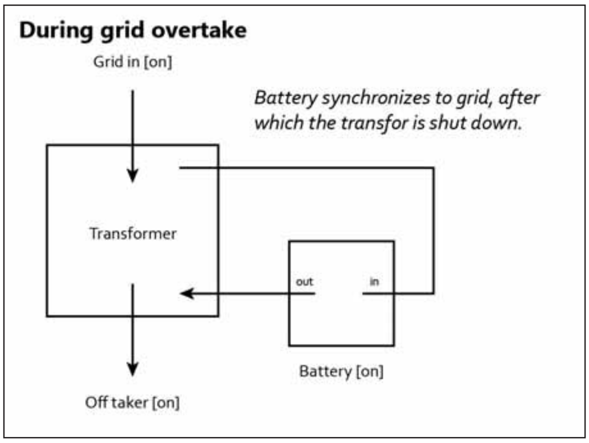


Figure 2. Energy data of a four-day event with a battery and a 63 amp grid connection





▲ **Figure 4. During grid overtake**

◀ **Figure 3. Grid before maintenance**

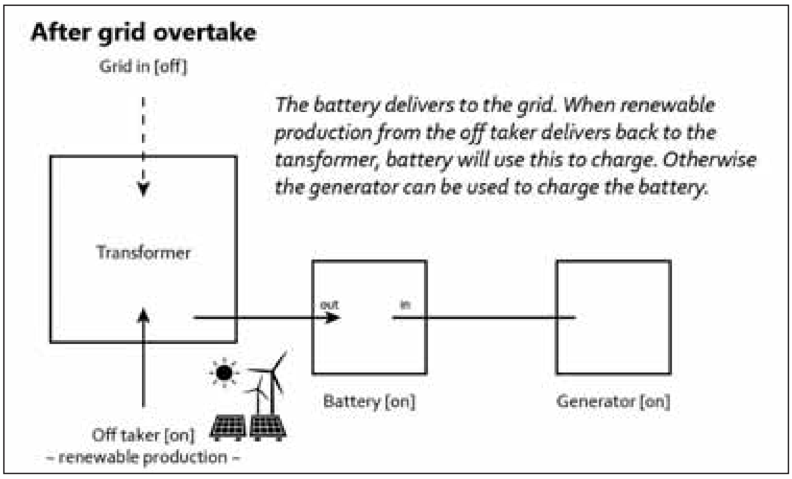


Figure 5. After grid-overtake

the battery as a "peak shaver" (see Figure 2);
3. Low noise: during the night hours the battery can provide the complete supply of power;
4. Energy reduction: energy generated by renewable sources delivered back to the grid during the day is stored in the battery and can power the grid at nighttime;
5. Compact arrangement makes ideal use in urban areas;
6. Reliable and clean power;
7. The grid can be taken-over without the power going out.

How would this new situation work?

Let us first define three situations when a grid take-over happens. These three scenario(s) will be explained in more detail after:

1. Before grid overtake
2. During grid overtake
3. After grid overtake

Before grid overtake

Prior to maintenance, the grid requiring maintenance supplies power to the off-taker via a transformer, as shown in Figure 3.

During grid over-take

When the battery is in place, and the maintenance can start, the battery will synchronise to the grid and start delivering power to the off-takers, alongside the power that is delivered by the transformer. See Figure 4.

The battery can now even take over all the power consumption that is happening on the off-taker's side, so the electricians can safely disconnect the grid at the transformer side.

After grid over-take

When the power is disconnected at the transformer side, the battery is solely providing all the power that is needed on the off-taker side.

Whenever there is an overproduction of solar energy from rooftops, the battery will start charging, or when there is an underproduction, the battery will deliver the power that is required.

In order to guarantee that the power is always there, a diesel generator is attached to the input of the battery, so that it can charge back up on 70% of the diesel generator capacity in the shortest amount of time. The new situation looks as Figure 5.

What is the upside?

Batteries provide the event with energy, and when the state of charge of the battery reaches a certain threshold, the generator will charge the battery at its most efficient load of 70%. This method can reduce emissions by up to 62% and reduce operating hours of generators up to 85%. Next, to the reduction of emissions, this method also reduces the running time significantly, so there is less noise from the generators. ■

Author

Dieter is a wind energy engineer who specialised in sustainability and green energy during his studies. His ideal of a world running solely on renewable energy is realised and spread through Greener power solutions, https://greener.nu

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